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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE CUSTOMERS	Docket No. E-1345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY	Docket No. E-1345A-05-0827

NOTICE OF FILING OF PHELPS DODGE MINING COMPANY AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION CLOSING BRIEF

Arizona Corporation Commission
DOCKETED

JAN 22 2007

DOCKETED BY NR

FENNEMORE CRAIG
PROFESSIONAL CORPORATION
PHOENIX

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC"), hereby submits its Closing Brief in the above captioned Docket.

RESPECTFULLY SUBMITTED this 22nd day of January 2007.

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
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PHELPS DODGE MINING COMPANY AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

CLOSING BRIEF

January 22, 2007

FENNEMORE CRAIG
PROFESSIONAL CORPORATION
PHOENIX

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC"), through undersigned counsel, hereby submits this Closing Brief in the above-captioned docket.

INTRODUCTION

As the Arizona Corporation Commission ("Commission") evaluates the various designs and proposals intended to shape APS's rates and charges in this proceeding, it must consider and give weight to the economic impact a rate increase will have on APS's ratepayers, irrespective of size or class. Ultimately, the Commission must arrive at a result that is just and reasonable.

SUMMARY OF POSITION

This Closing Brief sets forth AECC' s final position on matters raised during this proceeding. The evidence presented in pre-filed written testimony and at hearing demonstrates that, in furtherance of the public interest, the Commission should: 1) adopt AECC expert witness Kevin C. Higgins' recommended adjustments to APS's proposed revenue requirement, as well as his modifications to APS's cost-of-service and rate designs proposals; 2) adopt AECC's recommended approach to rate spread; 3) reject certain specific proposals that are unjust and/or unwarranted; and 4) approve certain specific proposals supported by AECC offered by Kroger Foods, Inc. ("Kroger"), the Federal Executive Agencies ("FEA") and Commission Staff witness Barbara Keene.

AECC does not address each and every issue raised during these proceedings in this Closing Brief. However, the evidence presented in pre-filed written testimony and at hearing supports the following proposed adjustments:

1. Reduce APS's proposed revenue requirement by $134 million dollars;
2. Adopt APS's 4-CP methodology for allocating fixed production costs;
3. Approve AECC's modifications to APS's cost-of-service analysis;
4. Adopt AECC's recommended rate spread;

5. Set APS's retail transmission and ancillary services rates equal to the corresponding rates in Schedule 11 in APS's Open Access Transmission Tariff;

6. Implement any APS generation rate increase for Rates E-32 [> 20 kW], E-34, and E-35 by increasing demand-related revenues and energy-related revenues by an equal percentage.

7. Establish that the "first 100 kW" and "all additional kW" of delivery charge would receive the same percentage increase;

8. Increase the Rate E-34 voltage discounts to more fully reflect cost-of-service differences between primary and secondary service; and

9. If approved, adopt the proportionate increase in the Environmental Portfolio Surcharge rates and caps recommended by Staff witness Barbara Keene.

1. Revenue Requirement

AECC makes four specific recommendations with respect to revenue requirements. AECC does not consider these recommendations to be comprehensive; rather they should be considered in conjunction with the revenue adjustments recommended by Staff and other parties. In total, AECC's four adjustments reduce APS's proposed revenue requirement by $134 million dollars relative to the Company's final (Rejoinder) position. These recommended adjustments include:

1. reduce fuel expense by $83 million (relative to APS' final fuel expense proposal filed in the Company's Rejoinder Testimony) consistent with the modifications made by APS in its request for interim relief and modification to Decision No. 67744 ("Interim Proceeding")[1];

2. reduce Administrative & General ("A&G") expense for the Pinnacle West Energy Corporation ("PWEC") units by $6.4 million, taking into account modifications made by APS in its Rebuttal Testimony;

[1] APS Emergency Interim Rate Increase and Amendment to Decision No. 67744, Docket No. E-01345A-06-0009, Decision No. 68685 (May 5, 2006), attached hereto as **Exhibit 1**.

3. reduce Operations and Maintenance (O&M") expense for the PWEC units by $3.6 million; and

4. eliminate APS's proposed ratepayer financing of an accelerated recovery of APS's underfunded pension liability in the amount of $41.2 million.

Further, AECC recommends that the Commission reject APS' proposal to change various components of the 90/10 sharing mechanism in the PSA, as well as its proposed establishment of an Environmental Improvement Charge.

AECC's final position concerning these matters has not changed from the original position it set forth in pre-filed testimony and at hearing. [*See* Direct Testimony of Kevin D. Higgins, Revenue Requirement ("Higgins Dt.-RR"); Surrebuttal Testimony of Kevin D. Higgins ("Higgins Sb.")].

In addition, AECC recommends that the Commission reject APS's proposal for an attrition adjustment, and/or a provision for accelerated depreciation, as well as deny Staff's proposal to modify the existing PSA adjustor to include a prospective component.

2. <u>Cost of Service, Rate Spread and Rate Design</u>

With respect to several cost of service, rate spread and rate design proposals, AECC recommends that the Commission modify cost of service, rate spread and design proposal by:

1. accepting APS's use of the 4-CP method in allocating fixed production costs;

2. approving AECC's modification to APS's cost-of-service analysis in which the Company's hourly fuel and purchased power costs are allocated based on each class's actual usage for each of the 8,760 hours of the test year;

3. allocating APS's retail transmission costs to customer classes based on the retail transmission charges in Schedule 11 of the APS Open Access Transmission Tariff ("OATT");

4. adopting AECC's recommended rate spread, which is guided by the results

of its modifications to the APS cost-of-service study to reflect the hourly allocation of fuel and purchased power costs; and

5. implementing any APS generation rate increase for Rates Schedules E-32 [> 20 kW], E-34, and E-35 by increasing demand-related revenues and energy-related revenues by an equal percentage. These are AECC's final positions concerning these matters. [*See* Direct Testimony of Kevin D. Higgins, Cost of Service ("Higgins Dt.-COS"); Higgins Sb].

Additionally, several proposals have been made on various issues during the course of these proceedings. In addition to the recommendations and proposals advanced herein, AECC supports three specific proposals made by other parties:

1. the proposal of Kroger witness Joseph S. Baron concerning Rate E-32 in which the "first 100 kW" and "all additional kW" of delivery charge would receive the same percentage increase. [*See* Direct Testimony of Joseph Baron ("Baron Dt.") at p. 25, line 9 – p. 27, line 3, Table 6].

2. the proposal by FEA witness Dennis W. Goins to increase the Rate E-34 voltage discounts to more fully reflect cost-of-service differences between primary and secondary service. [*See* Direct Testimony of Dennis Goins ("Goins Dt.") at p. 17, line 18 – p. 18, line 3].

3. if approved, the proportionate increase in the Environmental Portfolio Surcharge rates and caps recommended by Staff witness Barbara Keene. [*See* Direct Testimony of Barbara Keene ("Keene Dt.") at p. 12, line 25 – p. 14, line 5].

AECC asserts that adoption of these proposals will enhance the Commission's final order and help ensure that any resulting rate increase is spread equally among APS customers irregardless of size or class.

ANALYSIS

AECC's analysis of the various proposals made by parties during this proceeding fall into two general categories: 1) revenue requirement; and 2) cost of service, rate spread and rate design. Each category contains sub-issues that are discussed in more detail herein.

I. REVENUE REQUIREMENT

AECC recommends that the Commission reduce APS's overall requested revenue requirement by $134 million dollars relative to the Company's final position, for reasons more fully addressed below.

A. AECC's Proposed Adjustments

> 1. *Fuel Expense* - reduce fuel expense by $83 million relative to the Company's final position consistent with the modifications made by APS in the Interim Proceeding.

In the Company's rebuttal testimony filed in the Interim Proceeding, APS acknowledged that fuel and purchased power costs had declined by about one-third relative to the November 30, 2005 forward prices that form the basis for the fuel expense used in this general rate case. In his Rebuttal Testimony filed March 13, 2006, Company witness Peter Ewen stated that using the normalized and adjusted test year, the Company's fuel-related expense in the general rate case filing would decline by $67 million relative to the Company's direct filing in this proceeding if February 28, 2006 prices held. [*See* Rebuttal Testimony of Peter Ewen, Docket No. E-01345A-06-0009, attached hereto as **Exhibit 2**, at p. 2, lines 12-15].

However, in his Rebuttal Testimony filed in this proceeding, Mr. Ewen did *not* recommend a $67 million fuel expense decrease relative to his direct testimony, but instead recommended a fuel expense *increase* of $32.3 million. [APS Schedule CNF-2RB at p. 7]. Mr. Ewen later reduced this amount by $16.6 million in his Rejoinder Testimony. [APS (Final) Schedule C-1]. Thus, the final APS recommendation is to increase fuel and purchased power expense by $15.7 million relative to the Company's initial recommendation (i.e., $32.3 million - $16.6 million).

Mr. Ewen's fuel and purchased power revisions are driven largely by the fact that he has *changed the test period* used for evaluating fuel and purchased power prices from

2006 to 2007. [Transcript ("Tr.") at Volume ("Vol"). V, p. 1039, line 21 – p. 1045, line 19]. However, the test period used for setting rates should not be permitted to evolve between the time the Company files its Direct case and the time it files its Rejoinder Testimony. Fuel prices in 2006 did not change significantly from the projections used by APS in Mr. Ewen's March 13, 2006 Rebuttal Testimony noted above, which justified a $67 million reduction from the Company's direct filing. [Higgins Sb. at p. 16, lines 13-16]. As those prices generally held during 2006, the $67 million reduction in fuel expense relative to the Company's Direct filing ($83 million relative to its Rejoinder filing) should be adopted in this proceeding.

2. *PWEC Administrative & General Expense* - Reduce Administrative & General expense for the PWEC units by $6.4 million from APS final position.

APS witness Laura L. Rockenberger initially proposed an adjustment that would recognize $20.4 million in A&G expense for the PWEC generating facilities. [*See* Direct Testimony of Laura Rockenberger ("Rockenberger Dt"). at p. 15, lines 16-22]. These generating units were allowed into APS rate base as a result of the Settlement Agreement approved by the Commission in the previous APS general rate case (Decision No. 67744, April 7, 2005; Docket No. E-01345A-03-0437), attached hereto as **Exhibit 3**.

In its direct case, AECC recommended disallowing $11.5 million of this A&G expense as the amount of A&G expense for the PWEC units proposed by Ms. Rockenberger greatly exceeded the A&G expense attributed to these units by APS in the prior rate proceeding, when the net benefit of including the PWEC units in rate base was evaluated by the parties to the case, and ultimately, by the Commission. [Higgins Dt.-RR at p. 7, line 18; Decision No. 67744, p. 12, lines 11-28]. In her Rebuttal Testimony, Ms. Rockenberger reduced her recommended adjustment by $5.1 million. [*See* Rebuttal Testimony of Laura Rockenberger ("Rockenberger Rb.") at p. 16]. The remaining difference between AECC and APS with respect to this adjustment is now $6.4 million (i.e., $11.5 million – $5.1 million).

APS's proposal in the prior rate proceeding to allow the PWEC units into rate base was strongly contested by a number of parties. However, after extensive negotiation, the parties were ultimately able to negotiate a package that allowed these units into rate base with a partial disallowance – an arrangement that was subsequently approved by the Commission after careful scrutiny. [**Exhibit 3** -- Decision No. 67744, p. 12].

A major consideration in resolving this matter was the evaluation of the net benefit to APS customers of allowing the PWEC units into rate base. This evaluation included an analysis of the expenses associated with the units if they were allowed into rate base. In that analysis, APS depicted the annual A&G costs associated with the PWEC units as $8.797 million.[2] Had the A&G expense been depicted as $20.4 million, as Ms. Rockenberger initially proposed, or as $15.3 million, as APS now proposes, it would have negatively impacted the economic evaluation of allowing the PWEC units into rate base, and would reasonably have been expected to impact the final package negotiated by the parties and approved by the Commission. It is sound policy and follow-through to insist that the benefits to customers not be eroded in this proceeding by escalating the allowed A&G costs above the levels depicted by APS when APS was persuading the parties and the Commission that the PWEC units should be included in rate base.

It is appropriate, therefore, to limit the PWEC A&G expense to the level depicted by APS in the prior proceeding as part of the Company's analysis of the net benefits associated with bringing these units into rate base. [Tr. at Vol. XV, p. 3042, lines 8-13].

AECC's recommended adjustment of $11.5 million to APS' initial position is

[2] This amount was illustrated in APS Schedule DGR-8RB, and was discussed on page 58 of Mr. Robinson's rebuttal testimony filed in response to questions from Commissioner Gleason, Docket No. E-01345A-03-0437. Mr. Robinson described the A&G entry as "a fair representation of the A&G cost for the plants." *See* **Exhibit 4**.

shown on line 12, pages 1 and 2, of Attachment KCH-2. *See* **Exhibit 5**. AECC's final recommended adjustment of $6.4 million is simply the difference between AECC's initial adjustment and the $5.1 million reduction proposed by Ms. Rockenberger in her rebuttal testimony.

3. *PWEC Operations and Maintenance* - Reduce Operations and Maintenance expense for the PWEC units by $3.6 million

Ms. Rockenberger proposes an adjustment that would recognize $26.2 million in annual routine O&M expense and $10 million in normalized overhaul O&M expense for the PWEC generating facilities. [Rockenberger Dt. at p. 25, line 25 – p. 15, line 12]. These adjustments result in a combined O&M expense of $36.2 million per year. However, in the prior rate proceeding, APS depicted the combined O&M expense for the PWEC units to be $32.7 million. [**Exhibit 4** -- Docket No. E-01345A-03-0437, APS Schedule DGR-8RB, p. 3, line 9.] This situation is similar to the A&G issue discussed above. Had the PWEC O&M expense been depicted as $36.2 million, as APS now claims, it would have negatively impacted the economic evaluation of allowing the PWEC units into rate base, and would reasonably have been expected to impact the final package negotiated by the parties and approved by the Commission. For this reason, AECC recommends limiting the annual O&M expense for the PWEC units to the amount indicated by APS in the prior rate proceeding, when the case for including the PWEC units in rate base was being advocated by the Company. [Tr. at Vol. XV, p. 3043, lines 2-9].

AECC's recommended adjustment to PWEC O&M reduces APS's proposed revenue requirement by $3.6 million and is shown on line 9, pages 1 and 2, of Attachment KCH-2, attached hereto as **Exhibit 5**. AECC notes that maintaining consistency between the PWEC costs depicted in the prior proceeding and those allowed in this proceeding does not mean that PWEC-related costs should be permanently capped at these levels.

This rate proceeding is following relatively close in time to the decision that allowed the PWEC units into rate base. It is reasonable, at this time, to limit the O&M and A&G expense for these units at the amounts indicated by APS in the prior rate proceeding.

4. *Accelerated Recovery of Underfunded Pension Liability* - Eliminate the proposed ratepayer financing of the accelerated recovery of APS's underfunded pension liability in the amount of $41.2 million.

Ms. Rockenberger indicates that as of December 31, 2004, PWCC had an underfunded pension liability of $389 million, of which 92 percent, or $358 million, was attributable to APS. According to Ms. Rockenberger, of this latter amount, $218 million is "attributable to APS ratepayers;" that is, this amount is the portion not associated with APS personnel employed in support of jointly-owned facilities. [Rockenberger Dt. at p. 25, lines 6–20]. Ms. Rockenberger then proposes to increase ratepayer funding of pension expense by $41.2 million for five years to accelerate recovery of this underfunded pension liability. This would be booked as a regulatory liability, which would then be amortized for the subsequent ten years (i.e., 2012-2021) at $22 million per year. [*Id.*]

AECC asserts that ratepayer revenue should not be used to fund this accelerated recovery proposal. [Higgins Dt.-RR at p. 11, lines 2-3]. Both Commission Staff and the Residential Utility Consumer Office have registered similar objections to the Company's proposal. [Direct Testimony of James Dittmer ("Dittmer Dt.") at p. 64, line 20 – p. 65, line 7; Direct Testimony of Marylee Diaz Cortez at p. 19, lines 3-4]. The $389 million underfunded pension liability referenced by Ms. Rockenberger is the difference between the Potential Benefit Obligation ("PBO") of $1.371 billion, and the Fair Value of the assets of $982 million. [Higgins Dt.-RR at p. 11, lines 3-5]. However, according to the actuarial study performed for PWCC by Towers Perrin (September 2005), PWCC's PBO includes $233 million of projected obligation due to future salary increases. [*See* Towers-Perrin Report, p. SI-2, attached hereto as **Exhibit 6**]. Removing these projected future salary increases from the PBO produces the measurement known as the Accumulated Benefit Obligation ("ABO"), which is the present value of accumulated benefits based on service and pay as of the measurement date. The ABO as calculated in the actuarial study equals $1.138 billion. The difference between the ABO and the Fair Value of the assets is $156 million, of which $87.5 million is associated with APS employees not supporting jointly-owned facilities. [Higgins Dt.-RR, at p. 11]. This latter amount is much smaller than the $218 million the Company is seeking to recover over five years through its accelerated recovery proposal.

The APS proposal should be rejected because most of the $41.2 million rate increase would be funding a projected increase in benefit obligation that is based on *projected* salary increases that have not yet occurred. [Tr. Vol III, p. 423, line 23 – p. 424, line 6; Vol. III, p. 543, lines 15-22]. It is inequitable, unjust and unreasonable to require today's ratepayers to pay millions in current rate increases to recover a projected increase in pension benefits that is associated with salary increases that have not yet been realized. AECC's recommended adjustment to APS's proposal to accelerate recovery of pension expense reduces the Company's proposed revenue requirement by $41.2 million and is shown on Attachment KCH-3, attached hereto as **Exhibit 7**.

B. AECC Response to Proposals To Modify the PSA and/or Introduce New Ratemaking Mechanisms.

AECC supports APS's proposals to: (1) permanently eliminate or substantially raise the Total Fuel Cost Cap in the Power Supply Adjustor ("PSA"), and (2) change the cumulative 4 mill cap on the PSA adjustment to an annual cap. However, AECC recommends denying APS's proposal to change various components of the 90/10 sharing mechanism in the current PSA, and to establishment of an Environmental Improvement Charge ("EIC"). AECC also recommends denying APS's proposals for an attrition adjustment and/or accelerated depreciation as presented in the Rebuttal Testimony of

Steven M. Wheeler and Donald E. Brandt. Finally, AECC recommends denying Commission Staff's recommended modifications and changes to the current PSA.

1. *<u>APS's Proposed Changes to the PSA</u>* - APS's proposal to change various components of the 90/10 sharing mechanism in the PSA should be denied.

As discussed in Mr. Robinson's direct testimony, APS proposes that:

- The Total Fuel Cost Cap be permanently eliminated or substantially raised;
- The cumulative 4 mill cap on the PSA adjustment be changed to an annual cap; and
- The 90/10 cost sharing be eliminated for both renewable resources and the fixed costs of Purchase Power Agreements acquired through competitive procurement process.

AECC recommends adoption of the first two proposals and recommends rejection of the third. [Higgins Dt.-RR, at p. 14, lines 15-16]. The first two proposals are consistent with the terms of the PSA incorporated in the Settlement Agreement that was negotiated in the prior rate case, and which AECC supported. AECC continues to support the PSA mechanism as originally proposed.

The application of the 90/10 sharing mechanism to renewable resources and the fixed costs of PPAs was also part of the overall package negotiated and approved when the PSA mechanism was put forward to the Commission as part of the Settlement Agreement in the previous general rate case. [**<u>Exhibit 3</u>** -- Decision No. 67744, Attachment A]. APS now seeks to change these provisions. However, the balance of the equities in the PSA should not be changed absent a compelling public interest – and no such compelling public interest exists here, nor has APS demonstrated that one exists. With respect to the Company's obligation to purchase renewable energy, on pages 24-25 of his Direct Testimony, Mr. Robinson asserts that:

> In furtherance of [its] commitment to renewable energy, in Decision No. 67744 the Commission required APS to issue a Renewable RFP, seeking at least 100 MW and 250,000 MWhs of energy from renewable resources. It did so despite the fact that in many of its present applications renewable energy is significantly more expensive than conventional resources. Consistent with this Commission policy, APS should not be penalized by an automatic 10% cost disallowance when it acts in furtherance of that public policy by securing renewable resources that are not least-cost resources. [Direct Testimony of Donald Robinson ("Robinson Dt.") at p. 24, line 21 – p. 25, line 4].

What Mr. Robinson omits from this assertion is the fact that the requirement to issue a Renewable RFP, and to seek at least 100 MW and 250,000 MWhs of energy from renewable resources, is an obligation to which APS *voluntarily* consented in the Settlement Agreement it signed; the Commission did not impose these requirements – APS and the other parties to the Settlement Agreement presented these provisions to the Commission and sought the Commission's approval, which the Commission granted. [**Exhibit 3** -- Decision No. 67744 at p. 23, lines 15-18].

At the same time APS was agreeing to increased procurement of renewable resources, APS was agreeing that the 90/10 sharing would apply to renewable resources and the fixed costs of PPAs, all as part of having the PSA mechanism adopted. [*Id.*] Mr. Robinson now attempts to treat these components of the 90/10 sharing requirement in isolation, and argues for their removal from the sharing provision. [Tr. at Vol. IV, p. 823, lines 12-13]. This approach should be rejected for several reasons. These components of the 90/10 sharing requirement should not be viewed in isolation and removed piecemeal in this case. [Tr. at Vol XV, p. 3049, lines 6-17].

Further, APS's argument with respect to the fixed costs of PPAs should also be rejected on its merits. Mr. Robinson claims that it is appropriate to exempt the fixed cost component associated with market-acquired PPAs from the sharing provision because: (1) APS may be acquiring the gas used by the merchant generator, and thus would have the same incentive to do so prudently as it would for the Company's own units; and (2) an exemption would place PPAs on the same footing with regard to cost-recovery as APS-owned generation. [Robinson Dt. at p. 25, lines 12-16].

What Mr. Robinson's argument fails to acknowledge is that the inclusion of the fixed-cost components of a PPA in an *energy* adjustor is, in the first instance, a significant benefit to APS. Mr. Robinson's argument that PSAs should be placed on an equal footing with APS-owned generation is justification for the removal of the fixed-cost components of a PPA from the PSA *entirely* – not just from the sharing mechanism. [Higgins Dt.-RR, at p. 16, line 19 – p. 17, line 3]. Consider that the fixed costs of APS units are <u>not</u> part of the PSA calculation – changes in the recovery of these costs can only be implemented in a rate proceeding. It follows, then, that placing the fixed-cost recovery of APS generation and PPA generation on an equal footing would more appropriately involve excluding the fixed-cost components of PPAs from the PSA all together.

To be clear, AECC is not here proposing that the fixed-cost components of PPAs be excluded from the PSA. AECC is simply opposing the exclusion of these components from the 90/10 sharing arrangement, and is not proposing to change the terms of the PSA negotiated in the Settlement Agreement.

2. *<u>Environmental Improvement Charge</u>* – AECC recommends that the Environmental Improvement Charge be denied.

As explained in the Direct Testimony of Edward Z. Fox ("Fox. Dt.") and Gregory A. DeLizio ("DeLizio Dt."), APS is seeking approval of an Environmental Improvement Charge ("EIC") – an adjustment mechanism that would recover projected costs associated with installing and maintaining environmental upgrades at APS's generation facilities. [Fox Dt. at p. 8, lines 2-4; DeLizio Dt. at p. 3, lines 3-6]. According to the Company's proposal, the costs recovered under the EIC would include, but not be limited to, return on capital, depreciation, O&M expenses, property taxes, and associated income taxes. [DeLizio Dt. at p. 4, lines 2-4]. APS proposes that the first installment of the EIC be approved as part of this proceeding, and requests adoption of a .0152 cent-per-kWh EIC that would raise $4.3 million to recover planned costs associated with environmental improvements at the Company's Cholla generating facility. [Fox Dt. p. 8, lines 10-12].

Allowing a "stand-alone" rate adjustment for incremental environmental improvement costs is an example of "single-issue ratemaking," in which a single item is permitted to impact rates in isolation from all other rate considerations. *Scates v. Arizona Corp. Commission*, 118 Ariz. 531, 535, 578 P.2d 612, 616 (1978), attached hereto as **Exhibit 8**. In contrast, when regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. Unless it can be shown to involve a compelling public interest, single-issue ratemaking is generally not sound regulatory policy, as it ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. *Scates* at 535-536, 616-617. There is no compelling reason to permit single-issue ratemaking in this instance.

There are certain types of cost increases that regulatory commissions have come to allow without the benefit of conducting a general rate case. Because such exceptions constitute a form of single-issue ratemaking, it is not unusual for regulatory commissions to identify criteria that must be met for such treatment to be allowed, such as whether the costs in question exhibit volatility and/or whether the costs are largely outside the utility's control. *Scates* at 535, 616. In light of such criteria, the single-issue adjustments most commonly adopted are commodity and power cost adjustment mechanisms, such as the PSA mechanism approved by the Commission in APS's last general rate proceeding.

[**Exhibit 3** -- Decision No. 67744 at p. 16-18].

While APS is subject to current and future provisions governing environmental quality, these provisions are long-term in nature and do not change from month to month the way fuel costs change. Moreover, as is evident in the testimony of APS witness Fox, APS intends to bring a significant amount of judgment to bear on the nature and timing of the investments it will undertake, as the Company works to stay *ahead* of the regulatory curve through a dialogue with regulators and the environmental community. [Fox Dt. at p. 6, lines 5-6].

The appropriate forum for establishing rates to recover prudently-incurred utility investment is a general rate proceeding in which all cost and revenue information can be considered. *Scates* at 534-536, 615-617.

3. *APS's proposal for an attrition adjustment should be denied.*

The Company's proposal for an attrition adjustment was not part of its Direct filing, but appeared for the first time in its Rebuttal filing. [Wheeler Rebuttal Testimony at p. 18, line 3 – p. 19, line 20; Brandt Rebuttal Testimony at p. 28, line 5 – p. 30, line 20]. The proposed attrition adjustment would effectively ignore the massive efforts the Company undertook to prepare a historical test year analysis and neutralize any revenue adjustments made by Staff or Intervenors to APS's proposed revenue requirement [Dittmer Surrebuttal Testimony at p. 13, lines 7-20]. Such a mechanism would constitute little more than an "end run" around the general rate case proceedings and should be rejected.

4. *APS's proposal for accelerated depreciation should be denied.*

As is the case with the attrition adjustment discussed above, the Company's proposal for accelerating its depreciation by increasing its allowed depreciation expense appeared for the first time in its Rebuttal filing. [Rebuttal Testimony of Donald Brandt at p. 23, line 5 – p. 25, line 13.] The increase would not be based on detailed and systematic depreciation rate studies, and would not necessarily be FERC-account specific. [Dittmer Sb at p. 15, lines 18-22]. The Company's proposal for accelerating depreciation thus appears to be a gratuitous attempt to increase near-term cash flow without an underlying basis corresponding to the true life expectancy of the plant being depreciated. As such, it gives rise to serious inter-generational equity concerns. AECC recommends that this proposal be rejected.

5. *Staff's proposed modifications to the current PSA should be denied.*

Commission Staff's proposal to modify the existing PSA adjustor to include a prospective component is a dramatic change to the current form of PSA adjustor. [Higgins Sb. at p. 19, lines 14-15; Rebuttal Testimony of Donald G. Robinson at p. 3, lines 3-4]. This change alters the balance of equities struck when the PSA was first negotiated and has implications for the continuation of the 90/10 sharing mechanism, which was adopted to provide APS an incentive to control its costs. Further, implementing a prospective calculation into the methodology is likely to require a "doubling-up" of the adjustor in the first year, which will have negative rate impacts on customers [Higgins Sb. at p. 19, line 19 – p. 20, line 3]. The proposed change is not in the public interest and should be denied.

C. <u>Renewable Energy Standard and Tariff</u>

AECC participated actively in the Environmental Portfolio Standard ("EPS") workshop and REST rulemaking processes. AECC supports the utilization of cost-effective renewable energy, but has expressed concerns about the unknown cost impacts of increasing the REST Portfolio Percentage to 2.5 percent by 2010, 5 percent by 2015 and 15 percent by 2025, and has therefore proposed the adoption of performance standards linking future increases in the portfolio percentage to demonstrated improvements in performance or reductions in cost-per-kWh.

With respect to specific REST Surcharges in this proceeding, AECC supports the proposal by Staff witness Barbara Keene to adjust APS' RES surcharge rate and caps proportionately to fund the additional $4.25 million RES revenue requirement approved for APS in Decision No. 68668. [Keene Dt. at p. 4, lines 8-10]. Staff's recommendation for a proportional increase in the surcharge rates and caps is consistent with the terms of the settlement agreement approved in Decision No. 67744. [Keene Dt. at p. 12, line 25 – p. 14, line 5], and is consistent with the structure of the Sample Tariff included in Attachment A to Decision No. 68566, which AECC continues to support as the appropriate rate design for implementing RES charges. AECC does not support higher charges or changes to the caps specified in the Sample Tariff, which states as follows:

> Unless otherwise ordered by the Commission the Renewable Energy Standard Surcharge shall be assessed monthly to every retail electric service. This monthly assessment shall be the lesser of $.00498 per kWh or:
>
> A) For residential customers, $1.05 per service,
>
> B) For non-residential customers, $39.00 per service;
>
> C) For non-residential customers whose metered demand is 3,000 kW or more for three consecutive months, $117.00 per service; and
>
> D) For non-metered services, the lesser of (1) the load profile or otherwise estimated kWh required to provide the service in question or (2) the service's contract kWh shall be used in the calculation of the surcharge.

II. <u>COST OF SERVICE</u>

A. APS's use of the 4-CP method for allocating fixed production cost is appropriate given the Company's system load characteristics and should be accepted by the Commission.

APS's retail demands are driven by summer usage. [Higgins Dt.-COS, Figure KCH-1, attached hereto as **Exhibit 9**]. The Company's average peak of 6,629 MW in the four summer months is 50 percent greater than its average peak of 4,423 MW in the non-summer months. [*Id.* at p. 3, lines 23-33].

The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when APS's production capacity requirements are determined. Such an approach properly aligns the allocation of the Company's fixed costs with cost causation. [Tr. at Vol. XIV, p. 2780, lines 13-21; Goins Dt. at p. 6, lines 13-21; Baron Dt. at p. 6, lines 8-9].

1. *The Commission should reject the Peak and Average production cost allocation method proposed by Staff.*

Staff witness Michael Brosch proposes that the 4-CP approach should be replaced by the Peak and Average method. [Direct Testimony of Michael Brosch ("Brosch Dt.") at p. 10, lines 3-5, Attachment MLB-4]. The method is classified in the NARUC Cost Allocation Manual as a "Judgmental Energy Weighting" approach. According to this method, fixed production cost is allocated based on a combination of each class's share of coincident peak demand, as well as each class's share of energy usage. [Higgins Sb. at p. 7, line 5]. Although Mr. Brosch states that the 4-CP allocations performed by APS were generally reasonable and are comparable to the allocation methodologies previously employed in APS general rate case proceedings, he goes on to state that Staff believes the Company's cost-of-service study should utilize an energy-weighted allocation approach in order to reflect the use of production facilities throughout the year. [Brosch Dt. at p. 8, lines 3-6]. The Peak and Average study prepared by Mr. Brosch is Staff's attempt to incorporate an energy-weighting into the allocation of fixed production costs.

Staff's proposed Peak and Average methodology should be rejected. [Tr. at Vol.

XIV, p. 2781, lines 1-3; Tr. at Vol. XV, p. 2997, lines 16-18; Higgins Sb. at p. 8, line 16]. The average peak demand during APS's four summer peak months is over 50 percent higher than the average peak demand in the remaining eight months, and the new capacity being added to APS's system is driven by APS's growing summer demands. [Higgins Sb. at p. 8, lines 16-19]. The Peak and Average method attempts to shift cost responsibility for these capacity requirements by allocating fixed production costs on an energy basis, placing more of the cost burden on higher-load factor customers who use energy at a relatively constant level throughout the year, rather than those classes whose summer usage is driving the Company's need for production capacity. [Higgins Sb. at p. 8, lines 16-19; Surrebuttal Testimony of Dennis Goins ("Goins Sb.") at p. 7, line 5 – p. 8, line 12].

Most importantly, the Peak and Average method is conceptually flawed in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-counting contributes to the bias against higher-load-factor customers inherent in this method. [Higgins Sb. at p. 9, lines 7-10; Goins Sb. at p. 7, lines 5-24].

2. *If the Commission orders that an energy-weighted method be used to allocate fixed production costs, then the Average and Excess Demand method should be used instead of the Peak and Average approach, because the former avoids the analytical shortcomings of the latter.*

If fixed production costs are to be allocated on an energy basis, then there are approaches that are conceptually superior to the Peak and Average method. One such analytically-superior methodology is the "Average and Excess Demand" method. [Higgins Sb. at p. 9, lines 11-20]. This method is described at length in the NARUC Cost Allocation Manual and is used by both Salt River Project and Public Service Company of Colorado. [*Id.*] The "Average and Excess Demand" method avoids double-counting by allocating costs based on a combination of average demand and the *excess* of class non-coincident peak over average demand. This method meets Staff's stated objectives of using an energy weighting and allocates a share of fixed production costs to the classes using the system solely during off-peak periods. [*Id.* at p. 10, lines 7-10].

3. *The Commission should approve AECC's modification to APS's cost-of-service analysis whereby the Company's hourly fuel and purchased power costs are allocated based on each class's actual usage for each of the 8,760 hours of the test year.*

APS's fuel and purchased power costs vary considerably throughout the year, as well as during the course of each day. Generally, these costs are higher in summer, and for any given day, higher during the peak hours of the afternoon and evening. [Higgins Dt.-COS, at p. 9, line 22 – p. 10, line 4]. Yet, the Company's allocation of its energy costs across customer classes does not take into consideration the variation in class usage across seasons or time-of-day. The Company's approach simply allocates fuel and purchased power cost based on the system average cost throughout the year. [Higgins Dt.-COS at p. 8, line 21 – p. 9, line 8]. It makes no difference whether those kilowatt-hours are concentrated in high-cost summer on-peak periods, or lower-cost off-peak periods; each kilowatt-hour is assigned exactly the same weight. Such an approach understates the energy cost responsibility for those customer classes whose usage is more heavily weighted toward the more expensive summer and daily on-peak periods. In turn, this practice overstates the cost responsibility for the remaining classes. [Higgins Dt.-COS, at p. 8, line 21 – p. 9, line 8].

To better align the allocation of APS's energy cost with cost causation, AECC witness Higgins added a step to APS's cost-of-service analysis in which the Company's hourly fuel and purchased power costs were allocated based on each class's actual usage for each of the 8,760 hours of the test year. [*Id.* at p. 12. line 19]. Such a step better aligns cost responsibility with cost causation, improving fairness and encouraging efficiency in resource utilization through better price signals. The benefits of this approach have been recognized by a number of the expert witnesses in this proceeding, including Kroger witness Baron [Tr. at Vol. XV, p. 2978, line 10-16], FEA witness Goins [Goins Sb. at p. 9, line 21 – p. 10, line 2], and APS witness Rumolo [Tr. at Vol. XIV, p. 2802, line 10 – 2803, line 3], each of whom expressed support for the AECC proposal.

With the increasing sensitivity of energy costs to seasonality and time-of-use, and with rapid load growth causing great pressure on APS's summer costs, it is critical that Arizona begin using seasonal and time-of-use information in determining the allocation of energy costs to customer classes. [Tr. at Vol. XIV, p. 2802, lines 2-7] As the strong summer growth pushes up the system average cost of energy, all customers are negatively impacted – but the greatest percentage rate increases are occurring in the industrial sector.

As part of the record of the Interim Proceeding, APS indicated that if its rate increase proposal in this proceeding was approved, the Company's industrial customer rates would rise cumulatively in excess of 40 percent between mid-2003 and early 2007. [Higgins Dt.-COS at p. 10, lines 5-8]. This is a matter of very serious concern for Arizona economic development and sustainability. APS's industrial rates are already 52 percent higher than in neighboring Utah, 28 percent higher than in Colorado and 5 percent higher than in New Mexico.[3] [*Id.* at p. 10, lines 8-11.]

The pressure on industrial customer rates in Arizona is exacerbated by the lack of an hourly energy cost allocation in APS's cost-of-service study. While it is fair for industrial customers to pay their share of summer energy costs based on industrial summer usage, it is not fair for the cost of expensive summer usage of other customers to

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[3] All comparisons are for a 10 MW, 75% load factor customer. APS rates are for Rate E-34. Utah rates are calculated for PacifiCorp Rate 9, Colorado rates are calculated for Public Service of Colorado Rate Schedule PG, and New Mexico rates are calculated for Public Service Company of New Mexico Large Primary Voltage Rate.

be transferred to industrial customers via the averaging of annual energy costs in the cost-of-service study. And currently, that is what happens in Arizona. [Higgins Sb. at p. 10, lines 12-21]. As demonstrated by AECC witness Higgins, the use of annual average energy cost in assigning class energy cost responsibility is causing the rates for E-34 customers to be inflated by 3 percent, and is causing the rates for E-35 customers to be inflated by over 6 percent. [Higgins Dt.-COS at p. 11, line 1 – p. 12, line 7, Table KCH-2, attached hereto as **Exhibit 10**]. This evidence is un-refuted.

Fortunately, this problem can be corrected with only a modest net impact on the Residential customer class. Including an hourly energy allocator only increases the overall cost responsibility for Residential customers by 1.69 percent. [*Id.* at p. 14, lines 21-23, Table KCH-4, attached hereto as **Exhibit 11**]. When rate spread mitigation is taken into account, the net impact on Residential rates is even less. However, the beneficial impact on industrial rate schedules is more significant: the cost responsibility for Rate E-34 declines 3.01 percent and that of Rate E-35 declines by 6.13 percent. [*Id.* at p. 14, line 24-26].

III. RATE SPREAD

A. The Commission should adopt AECC's recommended rate spread, which is guided by the results of its modifications to the APS cost-of-service study to reflect the hourly allocation of fuel and purchased power costs.

In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. [Higgins Dt.-COS at p. 21, line 19 – p. 22, line 8].

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for classes that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers. [*Id.* at p. 22, lines 1-8].

These objectives are supported in the AECC proposed rate spread, which is implemented as follows:

1. Set Residential rates midway between system average percentage increase and Residential cost-of-service, as modified to include an hourly energy allocation.

2. Set the percentage increase for Street Lighting equal to Residential.

3. Set Rates E-34 and E-35 equal to cost-of-service, as modified to include an hourly energy allocation.

4. Set the percentage increase for Rate E-32, Water Pumping, and Dusk-to-Dawn equal to the respective cost-of-service for each, as modified to include an hourly energy allocation, plus the same percentage point increase necessary to fund the Residential rate mitigation. [Higgins Dt.-COS at p. 23, lines 3-11].

AECC's proposed rate spread, calculated at APS's initially-proposed revenue requirement increase of $450 million, is shown in Attachment KCH-3SR, columns (i) and (j). AECC's approach to rate spread is more reasonable than APS's, as APS's proposed rate spread fails to adequately consider class cost-of-service. The Company's cost-of-service study indicates that Residential rates would have to increase 27.05 percent to fund that class's share of the Company's requested $450 million base rate increase, if rates were set at Residential cost-of-service (as calculated by APS). Instead, however, APS proposes that Residential rates increase 21.14 percent, which is exactly the system average. [Higgins Dt.-COS at p. 16, lines 4-21].

To fund the resulting revenue shortfall, APS proposes that General Service rates increase to a level significantly higher than the cost to serve that customer class. [*Id.*] Specifically, the APS cost-of-service study indicates that General Service rates would have to increase 14.88 percent to be priced at cost, but instead APS proposes an increase for this class of 21.60 percent, which is even slightly higher than the Residential class. Within the General Service class, the industrial customer rates of E-34 and E-35 are proposed to be increased by nearly 25 percent, placing these rate schedules exactly on cost-of-service, as calculated by APS. Thus, under APS's proposal, the bulk of the subsidization burden falls to Rate E-32, which warrants a cost-based increase of 13.4 percent, as calculated by APS, but is proposed to receive an increase of 21.19 percent. [Higgins Dt.-COS at p. 16, lines 30-31]. APS's proposal to set the Residential increase at the system average – and to set E-32 rates almost 8 percent above cost in order to make this possible – is not equitable. [Goins Dt. at p. 11, lines 6-7]. Gradualism provides for mitigation of rate impacts – but rate increases for classes that are below cost-of-service should generally be set above the system average in order to move them more reasonably toward cost-based rates. This is accomplished under the AECC proposal.

IV. RATE DESIGN

A. APS retail transmission and ancillary services costs should be allocated to customer classes based on the retail transmission charges in Schedule 11 of the APS Open Access Transmission Tariff.

The transmission and ancillary services costs incurred by APS for retail sales are based on charges found in the OATT. [Rejoinder Testimony of David Rumolo at p. 3, line 5]. For customers with demand meters, these OATT charges are based on the customers' billing demands each month, and are not based on energy. [*Id.* at p. 3, line 12]. Yet APS has allocated transmission and ancillary services costs to its customer classes based solely on energy, proposing a flat 4.76 mills-per-kWh unbundled transmission charge for all customers. [Higgins Sb. at p. 19, line 16; Tr. at Vol. XIV, p. 2795, line 20] This approach is inconsistent with the manner in which transmission and ancillary services costs are charged to APS for retail service, and is not reasonable. Moreover, transmission costs are largely, if not entirely, demand-related, and are more properly allocated on a demand basis. [Higgins Sb. at p. 3, line 29 and at p. 19, lines 15-19; Baron Dt. at p. 12, line 12-14] Consequently, APS's transmission costs are not properly allocated to the appropriate customer classes. [*Id.*]

APS's cost-of-service and rate design witness agrees that it is reasonable for the Company's original transmission rate proposal to be changed in favor of simply charging the appropriate retail transmission and ancillary services rates in Schedule 11 of the OATT, with the caveat that the smallest E-32 customers be charged on an energy basis, rather than on a demand basis. [Tr. at Vol. XIV, p. 2795, lines 17- 20]. AECC strongly supports this approach, with the clarification that the E-32 customers with billing demands less than 100 kW can be reasonably billed in accordance with the corresponding OATT energy charge, whereas E-32 customers with billing demands of 100 KW or greater should be billed in accordance with the corresponding OATT demand charge. [Tr. at Vol XV, p. 3069, line 12 – p. 3071, line 2].

The retail transmission rates found in Schedule 11 are as follows:

Retail Class	Applicable Charge
1. Residential Class: (DA-R)	$0.00417/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$1.271/kW
b. Non-Demand Metered Customers	$0.00340/kWh
3. Large General Service 3000 kW and above:	$1.421/kW

The Schedule 11 ancillary services rates should be added to the amounts above to comprise the APS unbundled transmission charge.

B. Any APS generation rate increase for Rates E-32 [> 20 kW], E-34, and E-35 should be implemented by increasing demand-related revenues and energy-related revenues by an equal percentage.

The generation rate increases that APS has proposed for Rates E-32, E-34, and E-35 are heavily weighted on the energy charge, with a much smaller increase falling on the demand-related charges, as summarized in the table below.[4] [Higgins Dt. at p. 20, lines 12-21]. The net effect of APS's proposed generation rate design is that higher-load-factor customers would experience a much greater rate increase than lower-load-factor customers. This impact is demonstrated in the Company's Schedule H-4, which shows the customer bill impacts resulting from the Company's proposed rate changes.

APS Proposed Generation Rate Increases by Rate Component

Rate Schedule	APS Proposed Rev. Increase from Demand-Related Charges	APS Proposed Rev. Increase from Energy Charges
E-32 >20 kW	2%	53%
E-34	11%	53%
E-35	12%	48%

It is neither appropriate nor reasonable for APS to recover such a large proportion of its proposed generation rate increase on the energy charge of these rate schedules. AECC witness Higgins compared the Company's proposed unbundled generation *revenues* to the Company's energy and demand *costs* in its cost-of-service study. [*See* Attachment KCH-8, attached hereto as **Exhibit 12**]. For each of these rate schedules,

[4] Note that for Rate E-32, APS's generation-related demand costs are not collected through a demand charge, but are collected as part of the first energy block, which is collected on a "first 200 kWh per kW basis."

APS's proposed generation demand charge (or demand-related charge) under-collects the rate schedule's generation-related demand costs. At the same time, the Company's proposed generation energy charge over-collects the rate schedule's energy-related costs. This information demonstrates that the strong bias in APS's proposed rate increase toward increasing the generation energy charge is unwarranted. This bias unfairly impacts higher-load-factor customers and is unreasonable.

If a utility proposes a demand charge that is below the cost of demand, then the utility is going to seek to recover the revenue requirement for that rate schedule by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case here. For a given rate schedule, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors end up subsidizing the costs of the lower-load-factor customers within the rate class.

Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable. [Higgins Dt.-COS, at p. 21, line 19 – 23].

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning with costs minimizes cross-subsidies among customers. As stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable, unjust and unreasonable.

For Rate E-34, any generation rate increase should be implemented as an equal percentage increase on both the demand and the energy charge. This approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. [Higgins Dt. at p. 22, lines 10-16]. It will have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-32 customers with billing demands greater than 20 kW, any generation rate increase should be implemented as an equal percentage increase on the first energy block (i.e., the first 200 kWh/kW block) and the second energy block. [Baron Dt. at p. 25, line 9 – p. 27, line 3; Higgins Dt.-COS at p. 22, lines 17-19]. As is the case for Rates E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-35, any generation rate increase should be implemented as an equal percentage increase on the energy charges and on "demand charge revenues in the aggregate." For Rate E-35, demand charge revenues need to be treated on an aggregate basis due to APS's proposed change in the definition of the off-peak demand charge for this rate schedule. [Higgins Dt.-COS, at p. 23, lines 3-11]. As is the case for Rates E-32 and E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase.

CONCLUSION

Some rate increase for APS is likely given all the issues raised in this proceeding. No party is recommending a rate decrease. However, to the extent that the Commission seeks to establish just and reasonable rates for all customer classes, AECC asserts that adopting AECC's proposed recommendations will serve the public interest by making rates and charges reasonable for APS customers.

RESPECTFULLY SUBMITTED this 22nd day of January 2007.

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EXHIBIT 1

ACC Decision No. 68685

May 5, 2006

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

Arizona Corporation Commission
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR AN EMERGENCY INTERIM RATE INCREASE AND FOR AN INTERIM AMENDMENT TO DECISION NO. 67744.

DOCKET NO. E-01345A-06-0009

DECISION NO. 68685

OPINION AND ORDER

DATES OF HEARING: March 20, 21, 22, 23, 24, 27, 28, 29, 2006

PLACE OF HEARING: Phoenix, Arizona

IN ATTENDANCE:
Jeff Hatch-Miller, Chairman
William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

APPEARANCES:

Mr. Thomas L. Mumaw, PINNACLE WEST CAPITAL CORPORATION; and Mr. William Maledon, OSBORN MALEDON, on behalf of Arizona Public Service Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge;

Mr. Scott S. Wakefield, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Mr. Jarrett J. Haskovec, LUBIN & ENOCH, on behalf of the International Brotherhood of Electrical Workers Local Unions 387, 640 and 769;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Western Resources Advocates;

Mr. Michael Grant, GALLAGHER & KENNEDY, on behalf of Arizona Utility Investors Association;

Ms. Laura Sixkiller, ROSHKA, DeWULF & PATTEN, on behalf of UniSource Energy Services;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, on behalf of Southwestern Power Group II, LLC, Mesquite Power, LLC, and Bowie Power Station, LLC;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of Arizona Agricultural Group;

Lieutenant Colonel Karen White, on behalf of the Federal Executive Agencies; and

Mr. Christopher Kempley, Chief Counsel, and Mr. Jason D. Gellman, Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On January 6, 2006, the Arizona Public Service Company ("APS") filed an application with the Arizona Corporation Commission ("Commission") for an emergency interim rate increase and for an interim amendment to Decision No. 67744 (April 7, 2005) ("Application").

By Procedural Order issued January 9, 2006, a procedural conference to discuss the process for handling this matter was set for January 12, 2006. The January 12, 2006 procedural conference was held as scheduled.

On January 19, 2006, Staff filed a Notice of Filing Proposed Schedule which indicated that Staff, APS and the parties that participated in the procedural conference had agreed upon a procedural schedule. In accordance with that proposal, APS filed supplemental testimony on January 20, 2006.

By various Procedural Orders, intervention was granted to: Phelps Dodge Mining Company ("Phelps Dodge"), Arizonans for Electric Choice and Competition ("AECC"), the Residential Utility Consumer Office ("RUCO"), the Arizona Utility Investors Association, Inc. ("AUIA"), Arizona Agricultural Group ("AzAg"), Western Resource Advocates ("WRA"), Unisource Energy Services ("UES"), Southwestern Power Group II, L.L.C., Mesquite Power, L.L.C. and Bowie Power Station, L.L.C. (collectively "Power Group"), Arizona Water Company ("AWC"), the Town of Wickenberg ("Wickenberg"), the Arizona Community Action Association ("ACAA"), the Federal Executive Agencies ("FEA"), the International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Unions 387, 640 and 769 (collectively, "IBEW"), and the Arizona Competitive Power Alliance

("Alliance").

On January 27, 2006, a procedural order was issued setting a hearing in this matter.

A procedural conference was held on March 14, 2006 to discuss the scheduling of witnesses and other procedural matters. The hearing on this application was noticed as an A.R.S. § 40-252 proceeding in order to allow the Commission flexibility to modify its previous decisions.

The hearing was held as scheduled on March 20, 21, 22, 23, 24, 27, 28, and 29, 2006. APS presented testimony of Donald Brandt, Peter Ewen, Steven Wheeler, Steven Fetter, Elliott Pollack, David Rumolo, and Donald Robinson. Staff presented testimony of J. Randall Woolridge, Ralph Smith, William Gehlen, and Barbara Keene. RUCO presented testimony from Marylee Diaz Cortez; the Power Group presented testimony of David Getts; AECC presented testimony from Kevin Higgins; and IBEW sponsored testimony of Robert DeSpain.

On March 30, 2006, AECC/Phelps Dodge filed its Notice of Filing of AECC Late-Filed Exhibit No. 8 (Supplement to AECC Exhibit No. 7).

On April 7, 2006, Staff filed its Closing Brief and its late-filed exhibit S-11.

On April 10, 2006, RUCO filed its Post-Hearing Brief.

On April 11, 2006, APS, AECC/Phelps Dodge, AUIA, WRA, and the FEA filed their post-hearing briefs.

On April 12, 2006, the Power Group filed their Post-Hearing Brief.

DISCUSSION

In its Application, APS requests an interim rate increase of $299 million in additional annual electric revenues, or approximately a 14 percent increase, to be effective April 1, 2006, and subject to refund pending the Commission's final decision in APS' pending permanent rate application.[1] According to the Application, this increase represents only the higher annual fuel and purchased power costs the Company expects to incur based on 2006 prices as reflected in its January, 2006, updated filing in the permanent rate case, and thus is not an additional increase. Granting the emergency interim rate increase requested in the Application would result in an interim base fuel cost

[1] Docket No. E-01345A-05-0816.

of $.031904 per kWh. According the Application, APS earns no markup or profit on fuel and purchased power costs, and these costs are unavoidable and largely uncontrollable. The Application states that the requested interim base fuel rate also reflects expected 2006 operations at Palo Verde and the other APS power plants and is not impacted by any of the 2005 unplanned Palo Verde outages. APS' Application also requests that the Commission amend Decision No. 67744 (April 8, 2005) on an interim basis to remove the $776.2 million "cap" on total retail fuel and purchased power costs recoverable in rates.[2]

APS Position

In its rebuttal testimony filed on March 13, 2006, APS modified its request to $232 million due to declines in fuel prices between November 2005 and the end of February 2006.

According the Application, APS is experiencing a substantial operating cash flow deficiency that has already led to one downrating of its debt securities to the bottom rung of the investment grade ladder. According to the Company, this increases its financing costs by approximately ten to fifty basis points and decreases the marketability of its securities. APS believes it is likely that it will be further downgraded to non-investment "junk bond" status for the first time in its over 100-year history of service in Arizona if its interim rate relief to address the "massive under collection of fuel and purchased power costs" is not granted. The Application states that APS would be among the least credit-worthy non-bankrupt utilities in America and the Company's ability to successfully undertake the multi-billion dollar construction program the Company believes is necessary to render adequate utility service to its customers at a reasonable cost would be put in serious jeopardy.

Attached to the Company's application is an Affidavit by Donald Brandt, the Executive Vice-President and Chief Financial Officer for both Pinnacle West Capital Corporation ("Pinnacle West") and APS. Mr. Brandt is responsible for the finance, treasury, accounting, tax, investor relations, financial planning and power marketing and trading functions at Pinnacle West and APS. Mr. Brandt testified concerning APS' financial condition and credit ratings. APS must access the capital market to issue debt to fund a portion of the cost of the Company's infrastructure additions and improvement

[2] In Commission Decision No. 68437, the Commission amended Decision No. 67744 and allowed APS to defer costs above the $776.2 million "cap" pending resolution in this docket.

required to meet customer needs, including new and upgraded transmission and distribution facilities, generation plant improvements, new environmental control systems, and other service facilities. The Company's capital expenditure budget for 2006 is approximately $650 million, and during 2006-2009, capital expenditures are expected to be more than $3 billion and the Company will need to access the capital markets to issue over $1 billion of debt to fund the projects that make up the budget.

The cost that APS pays for the debt it must issue to fund the capital expenditures is based upon the credit ratings that it is assigned. According to Mr. Brandt, these costs increase dramatically when a Company's credit rating falls to non-investment ("junk") grade level and for that reason he believes that both APS and its customers have a strong interest in maintaining investment grade credit ratings. Mr. Brandt testified that the key financial metric examined by the credit rating agencies is the ratio of Funds from Operations to Debt ("FFO/Debt"). The FFO/Debt measures the sufficiency of a Company's cash flow to service both debt interest and debt principal over time. According to Mr. Brandt, because the Company is unable to collect in a timely manner a significant portion of its fuel and purchased power cost, an imbalance has developed between cash revenue and cash expense, thereby worsening the FFO/Debt ratio.

Mr. Brandt testified that in order for a company to maintain a BBB credit rating, Standard and Poor's ("S&P") expects a company to maintain a FFO/Debt of 15 percent to 22 percent for a Business Profile 5 and 18 percent to 28 percent for a Business Profile 6. On December 21, 2005, S&P changed APS from a Business Profile 5 to a 6, reflecting its assessment that APS faces increased regulatory and operating risk. The December 21, 2005 S&P Research Update indicated that "an additional factor contributing to PWCC's weakened business profile is the performance of Palo Verde nuclear units in 2005." S&P also downgraded APS' debt. According to Mr. Brandt, APS' borrowing costs have increased $1 million per year as the result of this S&P downgrade to BBB -. In addition, APS will incur an incremental 10-50 basis points, or $100,000 to $500,000 in additional interest costs per year for each $100 million of long-term borrowing. Further, Mr. Brandt testified that the downgrade imposed onerous restrictions on the Company's ability to access funds needed for its construction program. Mr. Brandt believes that absent emergency interim rate relief APS will likely be further downgraded to non-investment grade or junk bond status. Mr. Brandt testified that any further downgrade in APS' credit rating from its current BBB- rating to below investment grade could cause an immediate additional annual increase in interest expense in the range of $10 million to $15 million. Further, by 2015, the additional amount of annual interest expense would grow to $150 million to $230 million, for a cumulative amount of between $625 million and $1.2 billion in additional interest costs.

Mr. Brandt testified that the impact of downgrading from APS' current credit rating to non-investment grade would be costly in the following ways:

- During the next 10 years, APS will need to issue almost $5 billion worth of additional long term debt to finance essential generation, environmental control, transmission and distribution construction programs, and to refinance existing long-term debt when it matures. As a result, the Company's annual financing costs would increase between $110 million and $225 million over what they would have been if APS had not been downgraded to junk status;

- APS' approximate $539 million of tax exempt debt and the cost associated with this debt would increase an additional $4 million per year due to increased fees and additional interest.

- Because of the seasonal nature of APS' cash flow, APS relies heavily on commercial paper for its working capital needs. If APS were further downgraded to non-investment grade, its access to the commercial paper market would be eliminated and APS would be turning to its more costly revolving credit agreement to satisfy its daily working capital needs. This would increase APS' overall cost of borrowing by about $1 million per year.

- Further negative impacts include difficulty renewing existing credit agreements; negative effects to its marketing and trading functions including collateral calls which could place a significant liquidity strain on APS when the Company is least able to access the markets; in addition to cash collateral calls, energy trading counterparties may place other onerous terms on their dealings with a non-investment grade company including prepayments for a large portion of APS' power plant fuel needs, thereby making APS' cost of doing business in the wholesale market increase significantly and making it more difficult to hedge the Company's commodity position.

In his direct testimony, Mr. Brandt testified that the emergency the Company faces includes:

- An unprecedented increase in APS' fuel and purchased power costs since base fuel rates were established in Decision No. 67744 and continuing significant increases in those costs during 2006 due to ongoing exogenous factors and fundamental shifts in the global energy market.

- Continued cost deferrals in 2006 from the imbalance between fuel costs and cost recovery which has weakened the Company's key financial indicators and a further downgrade according to APS if the Commission does not address fuel cost recovery in a manner that promises to reverse the downward trend in the Company's financial indicators.
- A credit rating agency downgrade of APS to non-investment grade would increase interest expense in 2006 by at least $10 to $15 million, increasing to between $115 and $230 million by 2015.
- Credit limitations imposed on APS as a result of a further downgrading would increase the cost of fuel acquisition and purchased power.
- Once a Company experiences an important credit downgrade, it takes years of sustained positive regulatory action to reverse the situation.
- Without an interim raising of the $776.2 million cap, APS will be unable to defer approximately $65 million in 2006.
- Pending APS general rate case will possibly not be decided within a "reasonable time".

Mr. Brandt testified in his direct testimony that since the Affidavit and Application were filed, S&P issued an additional Research Summary regarding APS and both Moody's and Fitch have taken negative rating actions regarding the Company. According to APS witness Brandt, all three of the rating agencies point directly to the Company's increasingly critical need to recover in a timely manner fuel and purchased power costs prudently incurred to serve its customers as the basis for its negative action. Mr. Brandt testified that the combination of weak cash flow and the resulting need for additional debt will result in a weaker FFO/Debt ratio which will likely cause the downgrade of the Company to junk grade.

In his rebuttal testimony, Mr. Brandt states that the Company faces "an emergency situation and critically needs timely action by the Commission permitting the Company to recover its fuel and purchased power costs on a current basis. Without such action, the Company faces a continuation of its cash flow crisis and the very real and substantial risk of a downgrade of its credit ratings to non-investment 'junk' grade levels." (Brandt rebuttal p. 2) He testified that the recent reports of the credit rating agencies are clear that the recent "partial relief" granted by the Commission will not cure the Company's cost-recovery issues. He disagrees with Staff and RUCO witnesses' interpretations of those reports and believes that they have understated the risk and likelihood of a further downgrade. Mr. Brandt testified that putting off recovery of these costs "distorts the true cost of electricity, increases the total amount to be recovered, potentially shifts some of those true costs from current ratepayers to future ratepayers, and raises the very real possibility that ratepayers will be saddled with massive additional interest costs over the next decade if APS'credit ratings suffer a downgrade as a result of a decision by the Commission to defer recovery of these costs." APS exhibit 3, p. 36. At the hearing, Mr. Brandt presented his opinion of how the various proposals affected the risk probability that APS' credit rating would be downgraded to junk.[3] He also presented an exhibit that set forth APS' expectation as to what FFO/Debt would be obtained under the various proposals.[4] Mr. Brandt testified that neither the Staff's nor the AECC/Phelps Dodge proposal is a sufficient alternative to the requested emergency rate relief.

Mr. Peter Ewen, Manager of Revenue and Fuel Analysis and Forecast Department for APS, testified concerning the increasing costs of the Company is experiencing. Those costs include:

- Incremental sales growth and fuel mix. APS has one of the fastest growing territories in the country and growth is one of the dominant factors producing increased fuel and purchased power costs. The Company's incremental sales attributable to growth is met primarily with high cost natural gas and purchased power. This factor alone accounts for $147 million of the requested interim rate increase.

- Natural gas prices. Natural gas prices have increased dramatically since 2002 according to Mr. Ewen and coupled with purchased power price increases are responsible for a $330 million increase in the Company's base cost of fuel prior to the results of the hedging program.

- Purchased Power Prices. Prices for purchased power, most of which comes from natural gas generation also increased significantly.

- Coal prices. Coal prices increased 13 percent between 2003 and November 2005 and are projected to increase an additional 6 percent in 2006. These higher coal prices have raised the Company's base cost of fuel by $34 million.

- Hedging. All of the above price increases would have amounted to an increased fuel expense of approximately $364 million; however, that amount was reduced by more than $160 million through APS' hedging program.

According to Mr. Ewen, the requested amount reflects expected 2006 fuel and purchased power prices and corresponding hedging result; a credit for anticipated off-system sales margins; and, the effects of adding the Sundance Unit to the APS system. Mr. Ewen used the Company's

[3] APS Exhibit 6.
[4] APS Exhibits 4 & 9.

production cost simulation tool ("RTSim") to calculate the new base fuel rate. The RTSim is a computer model which replicates the dispatch of the APS system and is the primary fuel expense and off-system sales forecasting tool used by the Company in preparing its annual budgets, long range fuel forecasts, and near term operational plans. In his rebuttal testimony, Mr. Ewen testified that the Company had re-estimated its fuel expenses using February 28, 2006 forward prices and has modified its request downward by $67 million, to $232 million.

APS rebuttal witness Steven Wheeler testified about "modifications and enhancements" to the Staff and to the AECC/Phelps Dodge recommendations which he believes would decrease the likelihood of rating downgrades and would impact the continued buildup of uncollected fuel and purchased power costs. Mr. Wheeler further testified that he does not agree that resetting the base fuel rate prior to the conclusion of the pending permanent rate case is prohibited by the APS Settlement Agreement or Decision No. 67744.

APS witness Elliott Pollack testified that non-investment junk credit rating of a local electric utility will negatively impact businesses' perceptions about Arizona.

APS witness Steven Fetter testified concerning comments from the three major credit rating agencies and stated that "[t]o me, S&P's recent press releases about APS indicate that the rating agency is looking for additional support from the Commission for significant near-term cash recovery by APS for its power supply expenditures that were prudently-incurred." APS Exhibit 7, p. 14. He also testified if APS were downgraded to junk status, that there would be a "marked change in the investor profile" for APS and noted that "major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments, or 'junk bonds'" and that some mutual funds may also be affected. *Id.* at 20. Mr. Fetter advised the Commission that if the Commission views the deferred fuel and purchased power costs as prudently incurred, that he would "strongly encourage action before further degradation of APS' credit ratings occurs. While raising rates to provide such recovery is never a welcome task, there would be a much greater negative impact on customers if their rates were to go up due to a further downgrade of APS into below investment-grade status, while the issue of power supply cost recovery remained looming as a potential further rate escalator." *Id.* at 29.

APS witness Donald Robinson testified that the Staff recommendation is consistent with how the parties' viewed the Power Supply Adjustor ("PSA") working under the Settlement Agreement. Mr. Robinson testified that Staff's recommendation allows the PSA to better track changes in fuel costs, which then improves the Company's operational cash flow and resulting financial metrics. He believes that Staff's recommendation to allow surcharges would better match the payment of costs with the customers incurring those costs and would provide a better signal to customers concerning the cost of their use of energy and the value of conserving energy. At the hearing, Mr. Robinson testified about the Company's expenses related to advertising and bonuses for its officers in response to questions by Commissioners.[5]

APS witness Rumolo testified and presented exhibits on the bill impacts of the requested increase.

RUCO's Position

RUCO presented one witness, Marylee Diaz Cortez, on its behalf. Ms. Diaz Cortez testified that APS' Application does not reflect an emergency at this time. Ms. Diaz Cortez testified that prior to the issuance of Decision No. 68437 (February 2, 2006), there might have been a case to debate over whether APS' condition was such that its ability to maintain service pending a formal rate determination was in serious doubt, but since the issuance of that decision, there are no grounds for finding an emergency. Ms. Diaz Cortez testified that there is no longer any basis for a perception by the rating agencies that the Commission will not deal with the growing deferrals in a timely manner and so the threat of an imminent downgrade to junk bond status is reduced. Ms. Diaz Cortez cites S&P's statement in December 2005 and the fact that since the Commission voted on Decision No. 68437, two of the rating agencies have indicated that their present investment grade ratings are stable. Ms. Diaz-Cortez testified that on "January 26, 2006, S&P affirmed its current BBB –, even though two days earlier it had reported that it appeared unlikely the Commission would grant the pending emergency rate application." RUCO exhibit 5, p. 7. Also, while Fitch downgraded APS' rating for senior unsecured debt from BBB + to BBB on January 30, 2006, it reported a stable ratings outlook.

[5] See letters from Commissioner Mayes on January 11, 2006, and February 1, 2006.

RUCO concluded that the rating agencies view Decision No. 68437 as adequate to maintain APS' current investment grade ratings.

Ms. Diaz Cortez testified that since there is no emergency, rates cannot to be changed without a finding of fair value. She further testified that APS did not present evidence that it would be unable to continue to provide electric service absent emergency interim rate relief, citing APS' testimony that the deferrals have constrained only 20 percent of its equity returns. Ms. Diaz Cortez testified that RUCO's position is that "granting an emergency interim rate increase at this juncture would substantially change the terms of the settlement agreement and Decision No. 67744" because fuel and purchased power under or over recoveries were to be shared 90/10 between stockholders and ratepayers. *Id.* at 9. An emergency interim rate request would circumvent the sharing mechanism and result in 100 percent of the under-recovered fuel and purchased power cost being borne by ratepayers, thereby changing the terms of the settlement agreement and Decision No. 67744, and would harm ratepayers.

At the hearing, Ms. Diaz Cortez testified that RUCO supported the Staff recommendation for surcharges. Tr. p. 1692. She explained that "we may not have given it (PSA) all the characteristics it needed to deal effectively with such large escalating fuel prices and that maybe in this proceeding that something we might want to contemplate doing is amending that adjustor mechanism that we put in place back in April '05 so that it can deal effectively with the level of escalation that has actually come to be." Tr. p. 1695.

In its Post-Hearing Brief, RUCO stated that the deferred fuel balance is growing and could become problematic and that the Commission should modify the PSA to provide more timely recovery of fuel costs. RUCO supported Staff's quarterly surcharge proposal.

AECC/Phelps Dodge's Position

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC/Phelps Dodge") sponsored testimony of their witness, Kevin Higgins, in this proceeding. Mr. Higgins testified that in light of rising fuel and purchased power costs and the recent downgrade experienced by APS, some emergency relief is warranted. Mr. Higgins believes that an emergency interim increase sufficient to allow APS to attain a FFO/Debt ratio of 18 percent in 2006 is appropriate. He recommends that the ratio can be obtained through an emergency interim rate increase of $126 million in calendar year 2006. If this rate increase were implemented on May 1, 2006, revenue could be collected with an increase of approximately 7.8 percent. Mr. Higgins disagrees with APS' proposal to establish a new base energy rate in this proceeding as it would allow APS to avoid having to absorb its 10 percent share of the cost differential between the current base energy rate and its new proposed energy rate. Mr. Higgins proposes that the base energy rate should remain at the level established in APS' last general rate case and any revenues collected from the emergency surcharge should be applied as a credit against the PSA annual tracking account. This would recover the 90 percent cost share assignable to customers with the remaining 10 percent assigned to APS in accordance with the PSA mechanism. Under this recommendation, the new base energy rate would then be established in the pending general permanent rate case.

Mr. Higgins also opposed APS' proposed interim surcharge rate design. According to Mr. Higgins, although APS has stated that the proposed increase would be a 14 percent increase, Mr. Higgins believes that the Company's proposal would actually raise rates for many industrial customers by more than 20 percent. He believes that it is inappropriate in the context of an emergency rate filing with a limited record and restricted opportunity for analysis, to put in place disproportionate increases on different customer groups. He recommends that the only appropriate rate design would be an equal percentage increase for all customer groups and that this could be achieved through an equal percentage surcharge on total customer bills exclusive of PSA charges.

During the hearing, Mr. Higgins modified his $126 million surcharge recommendation in response to APS' rebuttal testimony that included decreased net fuel costs. However, as testified to by APS witness Brandt, the expected extended summer 2006 Palo Verde outage would cancel out the fuel cost reduction. In its Post-Hearing Brief, AECC/Phelps Dodge readjusted its recommended increase back to its original $126 million amount, indicating that using the Palo Verde outage costs to determine the amount needed to reach the targeted FFO/Debt ratio does not "constitute *de facto* prudence determination", nor will it allow the company to recover those costs, as the recommended emergency surcharge will only flow to the PSA Tracking Account as a credit against costs found to be prudent by the Commission.

The Power Group's Position

The Power Group sponsored testimony of David Getts, the Chief Financial Officer of Southwestern Power Group II, L.L.C. The Power Group supports the level of emergency interim rate relief that APS is able to demonstrate is necessary to maintain securities and financial instruments of investment grade quality. The members of the Power Group are competitors in the wholesale electric market in Arizona and APS is the largest potential purchaser of capacity and energy in the market. Mr. Getts testified that APS' creditworthiness can have a direct effect on the terms and conditions offered to it, because when APS' credit is at risk, that risk affects the financial exposure and profile of the supplier. This means that the price offered to APS will be higher, and the terms and conditions more stringent. Those costs, if prudent, will ultimately be passed on to customers.

IBEW' Position

The IBEW sponsored the testimony of its witness, Robert DeSpain, who testified that the situation APS is in was not caused by the level of compensation that it pays its employees.

Staff's Position

Staff provided testimony of Ralph Smith, Jay Randall Woolridge, Barbara Keene, and William Gehlen. Mr. Smith testified that the Commission's cap of $776.2 million does not currently constitute a financial emergency for APS because APS has not yet incurred fuel and purchased costs in excess of the cap and Decision No. 68437 has allowed APS to defer fuel and purchased power costs in excess of that cap. Mr. Smith recommends that APS should be allowed to defer fuel and purchased power costs in excess of the cap in 2006 with the actual costs incurred by APS being reviewed for whether they were prudently incurred.

Mr. Smith testified that APS has not proved that a $299 million emergency rate increase is needed because it has not demonstrated that that rate relief would: prevent future downgrades of APS' debt ratings; result in an upgrade of APS' debt ratings; result in lower long-term costs for its customers; or be appropriate under the circumstances.

In his direct testimony, Mr. Smith cites two reasons why the requested emergency rate increase would not necessarily prevent future downgrades: "emergency" rate increases are subject to refund; and other factors such as a sustained, unplanned outage at an APS plant during a peak demand period could result in a downgrade. He also points out that hitting a particular FFO/Debt ratio does not dictate a certain bond rating. Mr. Smith testified that granting an emergency rate increase as a way to provide for APS to collect fuel and purchased power costs is not a preferred alternative because it would be based on forecast estimates of fuel costs under collections rather than collection of actual costs already incurred; it would likely require incurring additional costs for a surety bond; APS has not proven that it is currently experiencing a financial emergency or cash flow crisis; and there is no assurance that increasing APS' rates by $299 million subject to refund would result in a bond rating upgrade or prevent a bond rating downgrade. Mr. Smith agreed that a downgrading of APS' debt to junk status would not be a desirable outcome because in addition to resulting in increased borrowing costs, it would impede the Company's access to credit.

Rather than grant APS emergency rate relief that is not needed, Staff recommended that the Commission should address any deferred fuel balances through means of quarterly surcharges. Staff testified that prompt action on the PSA surcharge request is a better and more appropriate way to address the Company's growing deferred fuel balance than the Company's request for emergency rate relief. Staff recommends that the functioning of the PSA be reviewed in the current APS rate case and be revised if necessary when additional operating expenses in 2006 can be taken into consideration. In the interim, in order to address any potential for growing fuel costs under collection that APS anticipates for 2006 and as the preferable alternative to an emergency rate increase, Staff recommended that the Commission allow APS to file for PSA surcharge request in 2006 on a quarterly basis if necessary. Commission Staff is willing to expedite the processing of the surcharge request by filing its recommendation no later than 30 days after APS' filing. Mr. Smith testified that allowing APS to make quarterly PSA surcharge filings if necessary in 2006 could function as a "safety valve" against financial pressure from carrying large deferred balances building to an emergency situation. He testified that it could help thwart an emergency situation from occurring later this year and could provide both the Commission and the Company with a ready means to address and prevent a potentially serious situation.

Staff recommends that regardless of whether an emergency rate increase is granted, the Commission should temporarily impose some additional reporting safeguards on APS in order to monitor any deterioration in APS' financial condition. Staff recommended that APS file monthly reports on APS' and Pinnacle West's cash position and financial ratios, their cash flow projections for the upcoming 12 months and notify the Commission immediately if any event occurs or is projected by APS to occur within the next 12 months which would constitute a default condition. Mr. Smith testified that this would enable the Commission to have an additional means of keeping apprised of any possible deterioration in APS' cash and financial situation.

Staff witness Dr. Woolridge testified concerning the impact of the recent bond rating downgrade on APS' financial condition, the cost of capital, ability to raise capital, and the Company's customers; an assessment of whether the downgrade constitutes a financial emergency; an evaluation of a likelihood of additional downgrades of APS' debt; and the impact of any such additional downgrade. Dr. Woolridge testified that although the downgrading of the Company's bonds certainly is not positive for the Company, recent reports from rating agencies and investment firms suggest that recent Commission actions appear to have stabilized the situation. Staff exhibit 1, pp. 2-3. Those agencies and firms reacted positively to the January 25, 2006 Commission decision to lift the cap on deferred costs and to advance the collection of deferred costs.

Dr. Woolridge discussed the role of financial ratios and the rating process and indicated that rating agencies consider many factors. These factors include many business risk indicators such as economic conditions of the service territory, competitive environment, regulatory climate, customers, and exposure to unregulated businesses. Ratio analysis is also part of the credit risk analysis performed by rating agencies.

Dr. Woolridge testified that it is important to note the fact that the ratios published by rating agencies for different bond ratings are not strict standards which must be met to achieve a particular bond rating. He also noted that of the three ratios reported by S&P, the only APS ratio that violates its guidelines for the BBB rating is FFO/Debt, with the other ratios falling within the range specified for S&P for a BBB rating. Dr. Woolridge testified that he does not believe the bond downgrading has restricted the Company's access to capital and the Company has presented no evidence to support that assertion. He testified that if the Company were to be downgraded to junk status, such an event would restrict the Company's access to capital. He further testified the Company has not presented any evidence that its bonds are about to be downgraded to junk status and noted that the rating status of the bonds by S&P, the only agency that has the Company's bond rating one notch above junk status, is stable. Dr. Woolridge did note that the downgrading of the Company's bonds to BBB – by S&P has caused a slight increase in the Company's overall cost of capital and his analysis indicates that as of January 2006, it was at 15 point basis points.

Staff witness Barbara Keene set out the various rate impacts on customer bills for each of the requested rate increases, surcharges and emergency rate increase requests. At the hearing, she testified that pursuant to Decision No. 67744, low-income customers on the E-3 and E-4 low-income discount rates do not pay either the adjustor rate or any surcharges.

Staff also presented the testimony of William Gehlen. Mr. Gehlen testified that Staff evaluated the assumptions APS used in calculating the various projections for uncollected fuel and purchased power expenses for 2006. Mr. Gehlen testified that the Company has developed a hedge implementation strategy with the intent to manage price risks that has been caused by increased volatility in the natural gas and purchased power markets. The Company has hedged 85 percent of its 2006 natural gas and purchased power requirements and so the projected uncollected fuel and purchased power cost changes are limited. Mr. Gehlen testified because of hedging, the greatest impact on fuel and purchased power expenses would be the loss of a nuclear or coal, base unit resource during the peak June through September period. APS would become even more reliant on its gas generating unit as well as the purchased power market which is indexed to the price of natural gas. Mr. Gehlen testified that this would result in a dramatic increase in gas and purchased power costs. Staff concluded that APS' projections for uncollected fuel and purchased power expenses are reasonable.

EMERGENCY RELIEF

Legal Standard

The Commission's authority to grant a utility emergency rate relief is part of its constitutional ratemaking authority, which has been construed as plenary and exclusive. Ariz. Const. art. 15 § 3; *Arizona Corp. Comm'n v. State ex rel Woods*, 171 Ariz. 286, 830 P.2d 807 (1992); *State v. Tucson Elec. Light and Power Co.*, 15 Ariz. 294, 138 P. 781 (1914). In *Scates v. Arizona Corp. Commission*, 118 Ariz. 531, 578 P.2d 612 (1978), the court discussed the Arizona Attorney General's Opinion No. 71-17 ("Attorney General Opinion") and the limited circumstances where interim rates should be used: when an emergency exists; when a sufficient bond has been posted guaranteeing refunds to customers if the rates are later found to be excessive; and when the Commission will be making a final determination of just and reasonable rates after a valuation of the utility's property. The parties cite the Arizona Attorney General Opinion for criteria to determine whether an emergency exists. The Opinion says:

> The foregoing authorities make it clear that, in general, courts and regulatory bodies utilize interim rates as an emergency measure when sudden change brings hardship to a company, when a company is insolvent, or when the condition of the company is such that its ability to maintain service pending a formal rate determination is in serious doubt.
>
> In addition, under the *Mountain States Telephone* case, *supra*, the inability of the Commission to grant permanent rate relief within a reasonable time would be grounds for granting interim relief.
>
> Perhaps the only valid generalization on this subject is that interim rate relief is not proper merely because a company's rate of return has, over a period of time, deteriorated to the point that it is unreasonably low. In other words, interim rate relief should not be made available to enable a public service corporation to ignore its obligations to be aware of its earnings position at all times and to make timely application for rate relief, thus preserving its ability to render adequate service and to pay a reasonable return to its investors.

APS argues that the language of the AG's opinion merely gives examples of situations requiring emergency relief, and that they are not the only circumstances that may constitute an emergency. In its March 13, 2006 filing addressing the legal criteria for emergency or interim relief, APS argues that the "undisputed unexpected large increases in fuel and purchased power cost constitute 'sudden hardship' of an extreme nature to the company. The evidence is that as a consequence of those increased costs and the inability of the company to obtain timely permanent relief, there is a real threat to the company's credit rating, which already has been recently downgraded. Finally, the undisputed evidence is that the company and its ratepayers will suffer substantial consequences if further downrating occurs." APS March 3, 2006 filing, p. 4. APS notes that the Attorney General's Opinion "did not conclude that emergency relief may be justified only by *past* economic events; no such limit is even suggested by the opinion." *Id.* p. 3. APS also discusses and summarizes Commission and other jurisdiction's decisions allowing emergency relief for prospective costs.

AECC/Phelps Dodge agrees with APS that the list in the Attorney General's Opinion was not intended to set forth the only conditions upon which the Commission could approve emergency interim rate relief. Citing several Commission decisions,[6] AECC/Phelps Dodge states that the Commission has granted emergency interim rate relief "not only in situations where only historical costs were evaluated, but also in situations where prospective costs threatened to severely impact the utility in a negative way." AECC/Phelps Dodge Post-Hearing Brief, p. 3. AECC/Phelps Dodge concludes that "Arizona law, and Commission precedent, support the conclusion that the Commission has sufficient authority to grant emergency interim rate relief when prospective costs are considered part of the circumstances that warrant an emergency." Id.

Staff argues that the Commission has broad discretion whether to grant emergency rate relief. In its brief, Staff states that while *Residential Utility Consumer Office v. Ariz. Corp. Comm'n*, 199 Ariz. 588, 20 P.3d 1169 (App. 2001) requires that an emergency must exist to grant APS the relief it requests, the question of what qualifies as an emergency is largely a question of fact for the Commission to decide. Staff stated in its March 13, 2006 Prehearing Brief that the Commission's authority to grant emergency rate relief "should not be limited to specific, narrowly tailored sets of facts, but should instead be focused upon whether the application alleges circumstances sufficiently urgent to concern the interests of the public."

The FEA disagrees with APS' position that the Attorney General Opinion is "merely instructive". FEA Post-Hearing Brief p. 5. It cites subsequent Commission decisions and argues that the Commission has interpreted the Attorney General's Opinion as setting forth criteria to evaluate when determining whether an emergency situation exists. The FEA believes that the Commission should determine whether interim emergency rates are appropriate under the framework set out in the Attorney General's Opinion and subsequent case law and Commission decisions.

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[6] Decision No. 67990 (July 18, 2005) Sabrosa Water Company; Decision No. 65914 (May 16, 2003) Pine Water Company; Decision No. 62651 (June 13, 2000) Thim Utility Co.

RUCO asserts that Arizona courts would "likely narrowly interpret the Commission's authority to determine that an emergency exists and that an exception to the requirement to set rates only upon making a finding of fair value is justified." RUCO Post-Hearing Brief, p. 5.

Factual Evidence Necessary for Emergency Finding

In its brief, APS states that the emergency that justifies the "interim rate relief arises from the perilous financial situation created by the extremely large – and growing – imbalance between the Company's fuel and purchased power costs and its current rate revenues." APS Post-Hearing Brief p. 1. APS also asserts that there is a "significant risk" that S&P and other credit rating agencies will further downgrade APS if the Commission does not permit "'timely and full' relief from its mounting unrecovered fuel and purchased power costs." APS witnesses testified that a further downgrade would be financially disastrous for APS, its customers and shareholders, and would have an adverse impact on the state's economy.

AECC/Phelps Dodge believes that rising fuel and purchased power costs, the recent downgrade, and the outlook for APS' FFO/Debt ratio in 2006 are sufficient reasons to provide emergency relief in order to avoid a further downgrade.

The Power Group points to evidence that if APS is downgraded to "junk", it would have an increase of between $600 million and $1.2 billion in its cost of capital, and its access to the capital markets would be severely restricted or foreclosed at a time when it needs to make substantial capital improvements. It adds that operating expenses, including higher prices for fuel and purchased power and the imposition of restrictive credit terms and conditions, would also be ultimately borne by APS ratepayers.

The AUIA cites to the "'sudden change' in its (APS') fuel and purchased power costs, the December/January rating agency business position and rating downgrades, current and expected deferral levels, resulting impacts on its FFO to Debt Ratio and likely drop to 'junk' status" as "hardships" to the company. AUIA Post-Hearing Brief p. 5. AUIA also pointed to APS witness Wheeler's testimony and concluded that "APS' ability to provide 'adequate service' is likely to be adversely impacted and the Commission cannot act quickly enough on the general rate case to affect that result this year." Id.

The FEA argues that APS provided "no evidence that a 'sudden condition' caused the growing deferrals of fuel and purchased power costs." FEA Post-Hearing Brief, p. 8. Nor has APS claimed that it is insolvent, facing a liquidity crisis, or unable to provide service to its customers. The FEA concludes that APS has not met the criteria that would allow implementation of interim emergency rates.

Staff reviewed recent Commission emergency rate proceedings and concluded that in the majority of the cases where the Commission approved emergency interim rate relief, the utility's crisis had already occurred or was occurring. Staff stated that the Commission is not bound to find an emergency when only certain parameters are met, but should look to the totality of the facts. Under Staff's analysis, the facts and circumstances do not justify a finding of an emergency.

Staff cites the testimony that there is no threat of insolvency or a liquidity crisis if the request is denied, and Staff disagrees with APS' assessment that the credit rating agencies' written reports indicate that a downgrade is imminent. Staff believes that the written reports themselves should be given more weight than APS witness Brandt's testimony about his conversations with rating agency personnel. Staff also notes that APS did not testify that it would be unable to continue to provide adequate and reliable service pending resolution of the permanent rate case. In its brief, Staff states that since "the concern of the rating agencies is over the PSA, then the direct solution is to address the PSA, either by allowing a quarterly surcharge or by increasing the 4 mil bandwidth rather than to implement emergency rates when no emergency exists." Staff Post-Hearing Brief p. 7.

RUCO argues that rating agency comments do not create an emergency, and that the Commission should focus on setting just and reasonable rates. If the Commission were to consider the rating agencies opinions, RUCO believes that it is not clear that a downgrade to noninvestment status is as likely as APS initially suggested. RUCO notes that APS' testimony focused on only one of the three credit metrics, and that S&P considers other factors, including the "effectiveness of liquidity management, corporate governance practices, and the regulatory environment." RUCO Post-Hearing Brief, pp. 7-8. RUCO also noted that the performance of Palo Verde is another factor that affects the credit rating and it is out of the Commission's control. Further, RUCO argues that the Commission's recent decisions to allow APS to begin recovering under its annual adjustor two months early and to approve a surcharge have adequately mitigated the rating agencies' concerns. RUCO argues that if S&P "truly expected that denial of interim rates would result in a downgrade, it would not declare its current rating stable two days after stating that it does not appear likely that emergency rates would be approved." RUCO Post-Hearing Brief, p. 11. RUCO's review of the testimony about the credit rating reports leads it to conclude that no rating agency is threatening an imminent downgrade of APS' credit rating to non-investment grade.

OTHER RELIEF

Although Staff believes that no emergency exists to warrant an interim emergency rate increase, Staff does believe that the concern over the growing large deferred fuel and purchased power costs in 2006 is legitimate and warrants Commission action. Staff believes that the fundamental concerns over timing and certainty are best addressed by modifying the PSA mechanism. Staff's recommendation is for a quarterly surcharge process whereby beginning in June 2006, APS would file a surcharge application to recover actual deferred costs. Under Staff's proposal, unplanned outage costs would not be included; all fuel and purchased power costs would be subject to a prudence review at a later time; the FFO/Debt ratio would improve to 16.6; and low income customers would be exempted from the surcharges. RUCO supports Staff's proposal, but does not support the APS recommended modifications, including making the surcharge automatic, without prior review.

Staff also sees some merit in the AECC/Phelps Dodge proposal, finding it an improvement over the company's request. The positive aspects are the timing, it preserves the 90/10 sharing agreement, and that there is only one rate impact. The negatives are that it is an emergency rate increase and is directly targeting and depends on meeting a specific FFO/Debt ratio of 18 percent. Staff recommends that the Commission should set just and reasonable rates using a traditional regulatory model.

Another method of modifying the PSA would be to expand the bandwidth of the annual adjustor.[7] Staff believes that the increased bandwidth proposal is also a reasonable way to achieve

[7] See, letters from Commissioner Gleason March 8, 2006, and from Chairman Hatch-Miller, March 23, 2006.

fuller and timelier recovery of deferred costs. Staff notes that: it is not an emergency rate per se; it can be readjusted if appropriate in subsequent proceedings; it can likely go into effect on May 1, 2006; it requires only one adjustment; the 90/10 sharing is preserved; it adjusts the bandwidth directly addressing the credit rating agencies' concerns; and because this proceeding was noticed as a A.R.S § 40-252 proceeding[8], can be adopted at this time. RUCO believes that this proposal could recover the existing and projected deferred costs for a single year, but its once-a-year implementation makes it less flexible in dealing with what could be an on-going problem of under-recovery.

ANALYSIS

Much testimony at the hearing concerned whether and under what certain circumstances a credit rating downgrade would occur. Language from the credit rating agencies' reports, bulletins, and updates was picked apart, "placed into context", explained and analyzed. The bottom line is that no party or the Commission will know what action, if any, will be taken or when, because those actions depend on future undetermined events and actions of entities not involved in this proceeding.

As a Commission, our role is to evaluate the Company's application from the broad perspective of not only what is in the Company's best interests, but also what is in the public's best interest. Although APS is appropriately concerned about its credit rating, deflecting responsibility for the position that APS has gotten itself[9] into does nothing to show the credit rating agencies that it should expect "sustained regulatory support" from the Commission. APS wants us to believe that our actions alone will determine the Company's future, when in fact, APS' internal decisions and its ability to manage its operations and respond to change is what fundamentally determines how it performs. It is in the best interests of all stakeholders, including APS management, shareholders, ratepayers, and the state, that APS continues to provide reliable service at reasonable rates.

Arizona law allows limited exception to the Constitution's requirement that rates should be set in conjunction with making a finding of fair value of the utility's property.[10] One of those exceptions is for emergency rates, and another exception that allows rates to increase without making

[8] See March 14, 2006 procedural conference transcript.
[9] APS agreed to base costs that it knew were probably insufficient and did not appeal the Commission's decision approving the settlement agreement with significant modifications to the PSA.
[10] Ariz. Const. art. 15, § 14; *Scates, Residential Utility Consumer Office v. ACC.*

a fair value finding is with automatic adjustment clauses. The parties have aptly set forth the applicable law concerning emergency rates and have differing views as to whether the facts presented rise to the level of an "emergency". Applying the conditions discussed in the Attorney General's Opinion, it is clear that APS is not insolvent. It is also clear that APS is able to maintain service pending a formal rate determination, albeit at a potentially higher cost. All of the parties seem to agree that APS is facing hardship because it has incurred and paid for substantial amounts of fuel and purchased power that it has not yet been able to recover through its current rate structure. The parties do not agree as to whether this "hardship" was the result of a "sudden change" as discussed in the Attorney General's Opinion. The parties also do not agree as to whether the possibility of a future downgrade is a sudden change causing hardship.

We agree with Staff that our authority to determine emergencies is not limited to specific, narrowly tailored facts, and that our ratemaking authority is sufficiently broad to enable us to grant relief tailored to many different situations. In some situations, that may be to grant emergency rate relief, and in other situations, the circumstances or public interest may require other forms of relief. Although not specified in the Attorney General's Opinion, we believe that another important factor in evaluating whether an emergency exists is whether there is some other form of relief that would address the asserted emergency besides the extraordinary remedy of interim emergency rates. APS' existing rate structure already has incorporated one exception to the constitutional fair value finding requirement in the form of the PSA mechanism. The PSA was established to address the very "emergency" asserted by APS, recovery of deferred fuel and purchased power costs. Given the existence of the PSA mechanism and our ability to modify it in this proceeding, we find that no "emergency" exists. We can address the hardship that APS is facing through modifications to the PSA mechanism and therefore, there is no reason to invoke another exception to the constitutional requirement by implementing emergency rates.

Although we find that an "emergency" does not exist, we do agree that some action should be taken to insure more timely recovery of APS' prudent fuel and purchased power costs. Taking action now will benefit APS ratepayers in the long run by: reducing the amount of interest accruing on deferred costs and thereby the amount that ratepayers will pay; by sending more timely and accurate messages to ratepayers as to the actual costs that are being incurred, thereby allowing them to adjust their consumption; and by increasing the likelihood that APS will remain investment grade and thereby maintain the lower capital costs that current rates are based upon.

Although we find merit in Staff's proposal to allow periodic surcharges to collect deferred costs, we believe that the timing will not significantly reduce the interest that accrues, nor will it give a very timely price signal that costs have increased and are being incurred. Multiple price changes in a short period of time can be confusing to ratepayers and may not send the appropriate price signals. The primary benefit of Staff's proposal is that the costs are not recovered until they are known and incurred. However, under Staff's surcharge proposal, Staff's review is not intended as a prudency review, but will just verify calculations and make sure unplanned outage costs are excluded. Tr. p. 2194 No party testified that APS' purchased power and fuel costs will be at or near the base costs established in Decision No. 67744, and in fact, APS is 85 percent hedged for 2006.

Accordingly, in order to prevent the continued build up of a large balance in the 2006 Tracking Account and the amount of interest that will accrue that will need to be collected from ratepayers beginning in February 2007, we will allow APS to implement an interim PSA adjustor to collect a portion of the 2006 purchased power and fuel costs that are above the base cost established in Decision No. 67744. We believe that this adjustor should be set to collect an amount that will leave no more than approximately $110 million (or the amount that will be collected using a 4 mil bandwidth starting in February 2007 once the 2005 adjustor ends) in the 2006 Tracking Account at the end of December 2006.

Accordingly, we will authorize an interim PSA adjustor for 2006 costs using a bandwidth of 7 mil beginning May 1, 2006.[11] This will increase the monthly median residential summer customer bill by $5.73 and the monthly average residential summer customer bill by $7.33. The monthly median residential winter customer bill would increase by $3.72 and the monthly average residential winter customer bill by $4.74.[12] Pursuant to Decision No. 67744, low-income customers on the E-3

[11] Amount of expected unrecovered purchased power and fuel costs for 2006 of $248 million, APS schedule 18(D), less 4 mil bandwidth recovery of at least $110 million in adjustor implemented in February 2007, leaving approximately $138 million for recovery through interim PSA adjustor in 2006. The interim PSA adjustor should continue until all 2006 Annual Tracking Account costs are recovered except the amount needed for the February 2007 4 mil bandwidth adjustor.
[12] Staff exhibit 9.

and E-4 low-income discount rates do not pay either the adjustor rate or any surcharges, and will not pay this interim PSA adjustor rate.

APS should include a separate schedule for this interim PSA adjustor in its monthly PSA filings and Staff should monitor on an ongoing basis whether APS is correctly accounting for the recovery. The amounts collected through the interim PSA adjustor, including any costs associated with unplanned outages, will remain subject to a prudency review at the appropriate time. In addition, all unplanned Palo Verde outage costs for 2006 should undergo a prudence audit by Staff. In the event that Staff or any party believes that APS is not implementing the interim PSA adjustor correctly, they should promptly notify the Commission.

By acting now, rather than waiting until February 2007 to begin collecting these costs, the ratepayers will be paying approximately five million dollars less in interest charges.[13] Further, it is important to highlight that this interim modification to PSA will not affect APS' earnings, it will only affect the timing of the already authorized recovery of prudent costs paid for fuel and purchased power.[14]

This modification of the PSA is an interim measure taken to address what we see as a significant and growing deferral of fuel and purchased power costs. We expect the parties in the pending permanent rate proceeding to propose modifications to the PSA that will address on a permanent basis, the issues with timing of recovery when deferrals are large and growing. We also expect the parties to explore other ways to implement a PSA and/or other tariffs that will give more accurate feedback in pricing terms, so that customers can modify their energy consumption in response to price.

When the Commission approved the PSA in Decision No. 67744, the 90/10 sharing mechanism was viewed as an important benefit for customers, particularly the use of off-system sales margins to offset the PSA balance. Because the adoption of the PSA entailed a shifting of risk from shareholders to ratepayers that fuel and purchased power costs would increase over the level established in base rates, the credit of off-system sales margins, or net off-system sales revenues, to

[13] APS exhibit 18 D shows annual interest of $5,493,000 compared with no more than one-half million dollars in annual interest with a 7 mil interim PSA adjustor.
[14] Tr. pp. 1078, 1443.

the PSA balance is a particularly significant feature of the PSA. This feature has not, as yet, produced the level of mitigation envisioned by the Commission when we approved the Settlement.

According to monthly reports filed by APS, the Company's gross revenues from off-system sales for 2005 were approximately $58.5 million with margins of approximately $18-20 million before the 90/10 sharing. Contrast these figures with SRP's approximately $473 million in gross revenues for fiscal year 2005 from off-system sales. SRP does not prepare "net" off-system sales revenue figures but it was able to establish a $55 million "rate-stabilization fund" derived primarily from these revenues. This fund may allow SRP to avoid passing on to its customers approximately $40 million in fuel and purchased power costs associated with outages at the Palo Verde Nuclear Generating Station ("PVNGS"), while APS has a pending surcharge application seeking recovery of $44.6 million associated with these same unplanned outages at PVNGS.

In Decision No. 67744 Staff was directed to commence a review of APS' off-system sales practices within three years of the effective date of the Order. Because of APS' disappointing off-system sales revenues, it is imperative that said review take place as part of the pending permanent rate proceeding. The review should compare APS' off-system sales revenues and practices with other electricity providers in the West. The review should also include an analysis of Pinnacle West Capital Corporation, its affiliates and subsidiaries' wholesale energy sales, including, but not limited to, how these wholesale transactions impacted, if at all, APS' off-system sales revenues. We expect the parties to fully explore ways of increasing APS' off-system sales revenues that will benefit both the Utility and its customers.

We reject APS' request to eliminate the 90/10 sharing and will not modify the amount of 2006 costs that APS can recover either now or in the general rate proceeding.

Rate Design

APS, Staff and RUCO support any recovery of increased purchased power and fuel costs being applied to customers' bills on a per kWh charge basis. They believe that both the base rates and the PSA currently collect fuel and purchased power through a per kWh charge, so any additional costs that are collected should also be recovered on a per kWh basis. AECC argues that the costs should be collected as an equal percentage increase to customers' base bills because it believes that it is inappropriate in the context of an emergency rate filing to put in place disproportionate increases on different customer groups. AECC/Phelps Dodge argues that high-load factor E-34 customers could experience percentage increases that are 70 percent higher than the system average. The FEA agreed with AECC's recommendation, arguing that E-34 customers could experience rate increases of as much as 20 percent, depending on load factor.

In its post-hearing brief, AECC/Phelps Dodge proposes a compromise that incorporates elements of both rate design proposals. The compromise would first allocate the emergency amounts to be recovered to both Residential customers and Non-Residential customers as a whole on a cents-per-kWh basis as proposed by APS. Then the emergency surcharge on Residential customers would be determined on a flat cents-per-kWh basis, and the emergency increase allocated to Non-Residential customers would be recovered through an equal-percentage surcharge on all Non-Residential customer base bills as AECC/Phelps Dodge proposed. Under this compromise proposal, the Residential customers would pay the same way as they would under the APS rate design, and Non-Residential customers would each pay an equal-percentage surcharge.

There is merit in both approaches and in the compromise proposal, but because these are energy costs that are recovered through the PSA mechanism, we find that it is appropriate to collect these costs through the PSA's kWh charge. If this were an emergency rate increase unrelated to costs normally passed through an adjustor mechanism, then perhaps we would be more inclined to apply the increase as a percentage on bills. There is no reason to alter the formula for collecting the costs solely because they are being collected sooner. We encourage industrial and commercial customers to address the issue of rate design in the pending rate case.

$776.2 MILLION "CAP"

In Commission Decision No. 68437, the Commission amended Decision No. 67744 and allowed APS to defer costs above the $776.2 million "cap" pending resolution in this docket. Staff supports the continued waiver of the $776 million cap until the permanent rate case is decided. No party proposed resolving the issues relating to the $776.2 million cap in this docket, and there appears to be general agreement that those issues should be resolved in the pending permanent rate case. Until that time, APS should be allowed to continue to defer those costs.

MISCELLANEOUS ISSUES

In its Post-Hearing Brief, APS argues that any changes to the 90/10 sharing requirement should not be considered in this proceeding. "Although it is true that APS believes that the 90/10 sharing arrangement should not be applied to unexpectedly large fuel and purchased power and that a delay in resetting the base rate cost of fuel in the general rate case should not work to the detriment of APS, those are matters that can be addressed in the general rate case and need not be addressed in this proceeding. For present purposes, it would be sufficient for the Commission to specify that any interim rate increase approved by the Commission will preserve for the general rate case the issue of whether and to what extent APS will be required to absorb 10% of that interim rate increase when the Commission establishes a new base rate in the general rate case." APS Post-Hearing Brief at p. 34. Since we are not authorizing an interim rate increase, there is no reason to "preserve" this issue for resolution in the general rate case. If APS also means by that language that the Commission may want to modify the Settlement Agreement and Decision No. 67744 in the general rate case to remove the 90/10 sharing of the 2006 costs, we are clearly not "preserving" any such issue. The Settlement Agreement and Decision No. 67744 are still in effect and any proposal to modify the amount of costs that APS is allowed to recover is substantive and entirely different from the procedural issue of the timing of collection of authorized costs.

In its Closing Brief, Western Resource Advocates states that this proceeding is concerned with short run solutions to APS' financial situation. WRA believes that long term solutions cannot be addressed in this proceeding, but should be addressed in APS' pending permanent rate case and in other proceedings. WRA believes that APS should reduce its dependence on fossil fuels for the production of electricity, and should look to significantly reducing demand for electricity through large scale, sustained energy efficiency programs, and use low cost renewable energy resources as a hedge against high fossil fuel costs. We agree that APS should be looking at ways to diversify its resources.

APS also argues in its Post-Hearing Brief that interim relief should not be conditioned or made subject to expense or dividend restrictions imposed on APS. APS believes that although the Commission can examine and exclude imprudent costs in the general rate case, it "would be inappropriate for the Commission to involve itself in internal corporate governance by dictating, directly or indirectly, whether and to what extent APS should advertise or sponsor local organizations with shareholder funds." APS Post-Hearing Brief, p. 36 APS believes that interim rate relief solely to recover deferred fuel and purchased power costs should not be conditioned on APS cutting unrelated expenses or be subject to further restrictions on dividends paid by APS. APS notes that it has already engaged in substantial cost cutting as a matter of corporate policy, and no party to the proceeding asserted that any of APS' costs or expenses are excessive or inappropriate. APS witnesses testified that the expenses are small and most of the advertising and sports sponsorship expenses are not included in the company's cost of services charged to APS customers.

In light of the growing costs of fuel and purchased power, we are concerned about the rate impacts on customers. APS should also share that concern and take all steps necessary to reduce its cost of service, which we will analyze in its rate case. However, APS should also look for ways to improve its cash flow, even looking at expenses that are borne by shareholders and not ratepayers, especially when the credit rating agencies are focusing on its FFO/Debt ratio.[15] Accordingly, while we are not imposing restrictions on APS dividend payouts or dictating that certain expenses be eliminated in this proceeding, we expect APS to manage its operations in such a manner (including its generation assets) that with the relief granted herein, together with the measures that APS itself adopts, its business profile returns to 5, its FFO/Debt ratio continues to improve and its credit rating remains investment grade.

We are particularly concerned about the rate impacts the growing costs of fuel and purchased power will have on the low and fixed-income customers who will be the hardest hit by the increase in energy costs. Therefore, we will require APS in its pending permanent rate case to propose ways to implement automatic enrollment in the E-3 and E-4 low income-discount rate schedules for those customers who participate in applicable means-tested assistance programs such as LIHEAP, Food Stamps, and Medicaid.

* * * * * * * * * *

[15] Staff exhibit 11 indicates that the 5 mil interim adjustor will raise the FFO/Debt ratio to 17.8 percent and we believe that APS should be able to find ways to further improve that ratio.

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On January 6, 2006, APS filed with the Commission an application for a $299 million, or 14 percent, emergency interim rate increase in annual electric revenues and for an amendment to Decision No. 67744, on an interim basis, to remove the $776.2 million "cap" on total retail fuel and purchased power costs recoverable in rates. In its rebuttal testimony filed on March 13, 2006, the Company modified its request to $232 million to reflect declines in fuel prices between November 2005 and the end of February 2006.

3. Intervention was granted to AECC, FEA, RUCO, AUIA, AzAg, Phelps Dodge, IBEW, AWC, WRA, UES, ACAA, Alliance, Wickenburg, AARP, and the Power Group.

4. Public comment was heard at the commencement of the hearing on March 20, 2006 and approximately 40 public comment letters have been received by the Commission's Docket Control.

5. By Procedural Order issued January 26, 2006, the hearing was set to commence on March 20, 2006, and procedural dates were established for the filing of testimony and evidence.

6. On February 14, 2006, APS filed notice of publication indicating notice of the emergency application was published in the Arizona Republic on February 4, 2006 as required by the January 26, 2006 Procedural Order.

7. The hearing was held as scheduled on March 20, 21, 22, 23, 24, 27, 28, and 29, 2006. Public comment was taken and testimony was presented by APS, Staff, RUCO, the Power Group, AECC/Phelps Dodge, and IBEW.

8. On March 30, 2006, AECC/Phelps Dodge filed its Notice of Filing of AECC Late-

Filed Exhibit No. 8 (Supplement to AECC Exhibit No. 7).

9. On April 7, 2006, 2006, Staff filed its Closing Brief and its late-filed exhibit S-11; on April 10, 2006, RUCO filed its Post-Hearing Brief; on April 11, 2006, APS, AECC/Phelps Dodge, AUIA, Western Resource Advocates, and the FEA filed their post-hearing briefs, and on April 12, 2006, the Power Group filed their Post-Hearing Brief.

10. In Decision No. 67744 (April 8, 2005) the Commission adopted the parties' Settlement Agreement and approved a PSA.

11. In Decision No. 68437 (February 2, 2006), the Commission denied APS' application for a surcharge, accelerated the implementation of the adjustor, and ordered the parties to file a revised Plan of Administration.

12. On December 21, 2005, S&P changed APS from a Business Profile 5 to a 6 and downgraded APS' debt to BBB-.

13. APS' borrowing costs have increased approximately one million dollars as a result of this downgrade.

14. Cost deferrals due to the imbalance between fuel costs and recovery have weakened the Company's FFO/Debt ratio.

15. APS believes that absent emergency interim rate relief APS will likely be further downgraded to non-investment grade status.

16. APS believes that during the next 10 years it will need to issue almost $5 billion in long-term debt to finance essential generation, environmental control, transmission and distribution construction programs, and to refinance existing long-term debt and if it is downgraded to junk status, the Company's annual financing costs would increase between $110 and $225 million.

17. Negative impacts of junk status include difficulty renewing existing credit agreement, collateral calls that could result in liquidity problems, the imposition of onerous terms and conditions in contracts in the wholesale market, and the elimination of access to commercial paper.

18. The expected balance in the 2006 Annual Tracking Account on December 31, 2006 is approximately $247,557,000.

19. Based on the facts and evidence presented, Staff concluded that no emergency exists

to justify the rate relief sought by APS, but does believe that concern over mounting fuel and purchased power deferrals is legitimate and sufficient to justify some action in this proceeding.

20. Staff recommended that the Commission modify the PSA to allow for quarterly surcharge requests.

21. Staff's recommendation balances ratepayer and Company interests by allowing the timely recovery of costs and by using actual costs; it addresses the concerns of the credit rating agencies; and it preserves the 90/10 sharing requirement.

22. AECC/Phelps Dodge agreed with APS that an emergency existed and proposed recovery of $126 million of 2006 deferrals through a surcharge to the Annual Tracking Account in order to reach a FFO/Debt ratio of 18 percent.

23. RUCO does not believe that an emergency exists, and at the hearing, RUCO testified in support of Staff's proposal, and rejected APS' proposed modifications to make the surcharge automatic upon application.

24. An important factor in evaluating whether an emergency exists is whether there is some other form of relief that would address the asserted emergency besides the extraordinary remedy of interim emergency rates.

25. APS' existing rate structure already has incorporated one exception to the constitutional fair value finding requirement in the form of the PSA mechanism which was established to address the very "emergency" asserted by APS, recovery of deferred fuel and purchased power costs.

26. Given the existence of the PSA mechanism and our ability to modify it in this proceeding, we find that no "emergency" exists.

27. The hardship that APS is facing can be addressed through modifications to the PSA mechanism and therefore, there is no reason to invoke another exception to the constitutional requirement by implementing emergency rates.

28. It is in the public interest to insure more timely recovery of APS' prudent fuel and purchased power costs.

29. Although rates will increase in the short term, APS ratepayers will benefit from the

modification to the PSA in the long run by: a reduction in the amount of interest accruing on deferred costs and thereby the amount that ratepayers will pay; by sending more timely and accurate messages to ratepayers as to the actual costs that are being incurred, thereby allowing them to adjust their consumption; and by increasing the likelihood that APS will remain investment grade and thereby maintain the lower capital costs that current rates are based upon.

30. Staff's proposal to allow periodic surcharges to collect deferred costs has merit but the timing will not significantly reduce the interest that accrues, nor will it give a very timely price signal that costs have increased and are being incurred.

31. Multiple price changes in a short period of time can be confusing to ratepayers and may not send the appropriate price signals.

32. The primary benefit of Staff's proposal is that the costs are not recovered until they are known and incurred.

33. Under Staff's surcharge proposal, Staff's review of the surcharge application will not be a prudency review, but will only verify calculations and insure that unplanned outage costs are excluded.

34. No party testified that APS' purchased power and fuel costs will be at or near the base costs established in Decision No. 67744, and with hedges, APS anticipates a balance in the 2006 Annual Tracking Account of approximately $248 million.

35. APS is 85 percent hedged for 2006.

36. In order to prevent the build up of a large balance in the 2006 Tracking Account and the amount of interest that will accrue that will need to be collected from ratepayers beginning in February 2007, it is prudent to allow APS to implement an interim PSA adjustor to collect a portion of the 2006 purchased power and fuel costs that are above the base cost established in Decision No. 67744.

37. This interim PSA adjustor should be set to collect an amount that will leave no more than approximately $110 million (or the amount that will be collected using a 4 mil bandwidth starting in February 2007 once the 2005 adjustor ends) in the 2006 Tracking Account at the end of December, 2006.

38. An interim PSA adjustor for 2006 costs using a bandwidth of 7 mil should be implemented beginning May 1, 2006.

39. The interim PSA adjustor will increase the monthly median residential summer customer bill by $5.73; the monthly average residential summer customer bill by $7.33; the monthly median residential winter customer bill by $3.72, and the monthly average residential winter customer bill by $4.74.

40. Pursuant to Decision No. 67744, the PSA requires that low-income customers on the E-3 and E-4 low-income discount rates do not pay either the adjustor rate or any surcharges, and those customers will not pay this interim PSA adjustor rate.

41. The implementation of the interim PSA adjustor will reduce the amount of interest the ratepayers will pay by approximately five million dollars and will preserve the 90/10 sharing requirement.

42. APS should include a separate schedule for this interim PSA adjustor in its monthly PSA filings and Staff should monitor on an ongoing basis whether APS is correctly accounting for the recovery.

43. The amounts collected through the interim PSA adjustor, including any costs associated with unplanned outages, will remain subject to a prudency review at the appropriate time. In addition, all unplanned Palo Verde outage costs for 2006 should undergo a prudence audit by Staff.

44. In the event that Staff or any party believes that APS is not implementing the interim PSA adjustor correctly, they should promptly notify the Commission.

45. The interim modification to the PSA will not affect APS' earnings, it will only affect the timing of the already authorized recovery of prudent costs paid for fuel and purchased power.

46. The modification of the PSA is an interim measure taken to address a significant and growing deferral of fuel and purchased power costs.

47. The parties in the pending permanent rate proceeding should propose modifications to the PSA that will address on a permanent basis, the issues with timing of recovery when deferrals are large and growing.

48. The parties should also explore other ways to implement a PSA and/or other tariffs that will give more accurate feedback in pricing terms, so that customers can modify their energy consumption in response to price.

49. In Decision No. 67744 Staff was directed to commence a review of APS' off-system sales practices within three years of the effective date of the Order. Because of APS' disappointing off-system sales revenues, it is imperative that said review take place as part of the pending permanent rate proceeding. The review should compare APS' off-system sales revenues and practices with other electricity providers in the West. The review should also include an analysis of Pinnacle West Capital Corporation, its affiliates and subsidiaries' wholesale energy sales, including, but not limited to, how these wholesale transactions impacted, if at all, APS' off-system sales revenues. We expect the parties to fully explore ways of increasing APS' off-system sales revenues that will benefit both the Utility and its customers.

50. We reject APS' request to eliminate the 90/10 sharing and will not modify the amount of 2006 costs that APS can recover.

51. APS proposed, and Staff and RUCO agreed, that any additional costs that are collected should be recovered on a per kWh basis.

52. AECC/Phelps Dodge proposed an equal percentage increase for all customer groups, applying an equal percentage surcharge on total customer bills, exclusive of PSA charges.

53. In its Post-Hearing Brief, AECC/Phelps offered a compromise that incorporates elements of both rate design proposals.

54. Because these are energy costs that are recovered through the PSA mechanism, it is appropriate to collect these costs though the PSA's kWh charge.

55. There is no reason to alter the formula for collecting the costs solely because they are being collected sooner.

56. The industrial and commercial customers should address the issue of rate design in the pending rate case.

57. All parties support the continued waiver of the $776 million cap until the permanent rate case is decided.

58. APS' long-term planning should include ways to diversify its resources in order to achieve and maintain reasonable, stable rates.

59. In light of the growing costs of fuel and purchased power, APS should take all appropriate steps necessary to reduce its cost of service while maintaining safe and reliable service.

60. APS should also look for ways to improve its cash flow, including looking at expenses that are borne by shareholders and not ratepayers, especially when the credit rating agencies are focusing on its FFO/Debt ratio.

61. Although we are not, at this time, imposing further restrictions on APS dividend payouts or dictating that certain expenses be eliminated, we do expect APS to manage its operations in such a manner (including its generation assets) that with the relief granted herein, together with the measures that APS itself adopts, its business profile returns to 5, its FFO/Debt ratio continues to improve and its credit rating remains investment grade.

62. Because the Commission is particularly concerned about the rate impacts the growing costs of fuel and purchased power will have on the low and fixed-income customers who will be the hardest hit by the increase in energy costs, we will require APS in its pending permanent rate case to propose ways to implement automatic enrollment in the E-3 and E-4 low-income discount rate schedules for those customers who participate in applicable means-tested assistance programs such as LIHEAP, Food Stamps, and Medicaid.

63. Staff's recommendation that APS file monthly reports on APS' and Pinnacle West Capital Corporation's cash position and financial ratios, including their projected cash flows, until the pending general rate proceeding is resolved is reasonable and should be adopted.

64. APS has declared itself to be in a state of financial duress that it claims warrants emergency rates. We believe that a responsible Company making such claims in these circumstances would cut unnecessary expenses, including "branding" related advertising, sports sponsorships, luxury sports suites and season tickets to sporting events. In response to questions from Commissioners, the Company stated that during the past two years it spent more than $14 million on advertising, luxury sports boxes and sports sponsorships, $410,000 on season tickets and $2 million to $3 million for out of state travel. The Company has also stated that it believes the contracts for the

sports sponsorships and some of the related advertising cannot be canceled without incurring cancellation fees and inviting potential litigation. However, some of the sponsorships are scheduled to end in 2006 and 2007, and the Company has stated that the majority of its 2006 advertisements have not yet been placed. We believe that as a responsible Company, APS would immediately begin eliminating some of these discretionary expenses. The resulting savings could be put to better use for both shareholders and ratepayers if APS used the savings to establish a Rate Stabilization Fund designed to shield customers from possible future rate increases. We do not believe the Commission should gratuitously inject itself into decisions relating to corporate management. However, the circumstances of this case suggest APS and the Commission work collaboratively to ease APS' cash flow burden. This requires the Commission to focus its attention on both APS' expenditures and revenues. We therefore believe this finding is appropriate and in the public interest.

65. In response to the need for additional operating funds, the Company's Board of Directors voted to eliminate bonuses for APS' executive managers ("officers") in 2006, resulting in a savings of between $4 million and $6 million. However, APS paid out approximately $29.9 million in incentives to other employees in 2006, including $1.9 million to more than 50 senior managers. The Commission believes that at a time when APS is asking for multiple rate increases, funds that might be used for such bonuses could be better directed toward mitigating the impact of rate increases on the Company's customers. We believe that APS in 2007 should continue to disallow bonuses for its executive managers ("officers"), as well as the Company's 50 senior managers. The resulting savings could be put to better use for both shareholders and ratepayers if APS used the savings to fund a Rate Stabilization fund, as discussed herein.

66. Throughout the course of the hearings on this matter the issue of requiring APS to conduct a benchmarking study on the effectiveness of its natural gas purchasing practices was addressed by the parties. The Commission has ordered at least one other utility to engage in benchmarking studies, most recently in the Southwest Gas rate case. Therefore we find that APS should engage in a benchmarking study on their fuel costs and hedging practices. We direct APS to work with Staff to file within 180 days of the effective date of this decision, as a compliance item in this docket, the benchmarking study as prescribed herein.

67. During the hearing questions were posed to APS about natural gas storage and efforts the Company is taking to develop such storage in Arizona. Natural gas storage will be beneficial for the Company particularly because the Company derives the majority of its power from purchased power or natural gas fired plants. Therefore we find that APS should file with Docket Control, by December 31, 2006, a report on the efforts that they are taking, either unilaterally or with other companies, to develop natural gas storage in Arizona.

CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-203, 204, 221, 250, 251, and 361.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. Notice was given that the Commission would consider this matter pursuant to A.R.S. § 40-252.

5. No emergency exits to warrant the implementation of emergency interim rates.

6. The PSA mechanism adopted in Decision No. 67744, should be modified on an interim basis pursuant to A.R.S. § 40-252 to allow for an interim PSA adjustor to collect a portion of the 2006 purchased power and fuel costs during 2006, instead of 2007.

7. The pending general rate proceeding is the appropriate proceeding to address the "cap" of $776.2 million adopted in Decision No. 67744, and until the issue is resolved in that proceeding, APS may continue to defer fuel and purchased power costs in excess of that cap.

8. The pending general rate proceeding is the appropriate proceeding to address permanent modifications to the PSA mechanism.

ORDER

IT IS THEREFORE ORDERED that Arizona Public Service Company is authorized to implement an interim PSA adjustor for purchased power and fuel costs incurred in 2006, consistent with the discussion herein, to become effective May 1, 2006.

IT IS FURTHER ORDERED that Arizona Public Service Company shall provide its customers notice of the interim PSA adjustor in its next monthly billing, in a form that is acceptable to Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company's request for an emergency interim rate increase is hereby denied.

IT IS FURTHER ORDERED that all unplanned Palo Verde outage costs for 2006 should undergo a prudence audit by Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall modify its monthly Power Supply Adjustor filings to include the separate interim PSA adjustor schedule as set forth herein.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file monthly reports on Arizona Public Service Company's and Pinnacle West Capital Corporation's cash position and financial ratios, including their projected cash flows, until the pending general rate proceeding is resolved.

IT IS FURTHER ORDERED that the issue of the timeliness of recovery of fuel and purchased power costs and any permanent modifications to Arizona Public Service Company's Power Supply Adjustor shall be further addressed in the pending general rate proceeding.

IT IS FURTHER ORDERED that Staff shall commence a review of APS' off-system sales practices as part of the pending permanent rate proceeding, including a comparison of APS' off-system sales revenues and practices with other electricity providers in the West. The review shall also include an analysis of Pinnacle West Capital Corporation, its affiliates and subsidiaries' wholesale energy sales, including, but not limited to, how these wholesale transactions impacted, if at all, APS' off-system sales revenues. The parties will fully explore ways of increasing APS' off-system sales revenues that will benefit both the Utility and its customers.

IT IS FURTHER ORDERED that Arizona Public Service Company and Pinnacle West Capital Corporation shall take appropriate steps to insure that Arizona Public Service Company's financial ratios remain investment grade.

IT IS FURTHER ORDERED that as part of its pending permanent rate proceeding APS shall propose ways to implement automatic enrollment in the E-3 and E-4 low-income discount rate schedules for those customers who participate in applicable means-tested assistance programs such as LIHEAP, Food Stamps, and Medicaid.

IT IS FURTHER ORDERED that APS shall, in consultation with Staff, hire an outside consultant to conduct a benchmarking study on their fuel costs and hedging practices. Further, APS shall work with Staff to file within 180 days of the effective date to this decision, as a compliance item in this docket, the benchmarking study as prescribed herein.

IT IS FURTHER ORDERED that APS shall file with Docket Control, by December 31, 2006, a report on the efforts that it is taking, either unilaterally or with other companies, to develop natural gas storage in Arizona.

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IT IS FURTHER ORDERED that Arizona Public Service Company may continue to defer fuel and purchased power costs in excess of the $776.2 million "cap" referenced in Decision No. 67744 until the issue has been further examined in Docket No. E-01345A-05-0816.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

Jeffrey M. Hatch-Miller
CHAIRMAN

William A. Mundell
COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 5th day of May, 2006.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT

DISSENT ____________________

LF:mj

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE CO.

DOCKET NO.: E-01345A-06-0009

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EXHIBIT 2

Rebuttal Testimony of Peter Ewen
Docket No. E-01345A-06-0009

March 13, 2006

REBUTTAL TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-06-0009

March 13, 2006

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REBUTTAL TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-06-0009)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND SET FORTH IN THAT DIRECT TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the impact of the change in market prices for gas and power on fuel expenses[1] since Arizona Public Service Company ("APS" or "Company") filed its emergency application using forward prices from November 30, 2005. I also discuss the impact on the Company's uncollected fuel balance of the power supply adjustment ("PSA") surcharge proposal offered by Utilities Division Staff ("Staff") and of the proposal by Arizonans for Electric Choice and Competition ("AECC"), and the impacts from the Company's suggested

[1] "Fuel expenses" is used in this testimony to mean fuel and purchased power expenses.

modifications to those proposals. Other APS witnesses discuss other aspects of these proposals.

Q. **PLEASE SUMMARIZE YOUR TESTIMONY.**

A. Market prices for gas and purchased power have declined, at least temporarily, since the Company filed its emergency application with estimates of its 2006 fuel expenses using November 30, 2005 forward prices. Indeed, those prices had declined by almost one-third through February 28, 2006 for the coming 12 months. The net reduction in APS retail projected fuel costs from these price changes amounts to $39 million because only the unhedged portion of the Company's fuel costs is affected by such price movements. Moreover, even with such dramatic price declines, the Company's gas and power hedges for the next 12 months still are about $10 million below market prices. Using the normalized and adjusted test year levels, the Company's fuel-related expense in our general rate case would decline by $67 million assuming the February 28, 2006 prices hold.

The Staff and AECC witnesses have proposed implementing alternative surcharge adjustments to help address APS's under-collection of fuel expenses. With the modifications proposed by the Company and discussed by APS witness Steve Wheeler, the Staff proposal does provide additional fuel expense recovery in 2006 but falls far short of the Company's interim rates request and will still leave a significant uncollected balance estimated to be approximately $241 million by year-end 2006.

II. <u>GAS PRICE DECLINES REDUCE FUEL COSTS</u>

Q. **HAS THE COMPANY RECALCULATED ITS FUEL EXPENSES BASED ON MORE CURRENT FUEL AND PURCHASED POWER PRICES?**

A. Yes. The Company re-estimated its fuel expenses using February 28, 2006 forward prices for March 2006 through February 2007. Forward prices for natural gas and on-peak power for those months were approximately 33% lower on February 28, 2006 than they were on November 30, 2005. At $60/MWh for on-peak power at Palo Verde and $7.13/mmbtu for natural gas delivered at the Company's in-valley gas plants, these prices are now close to the level they were in March 2005. As Staff witness William Gehlen noted in his testimony, the Company is 85% hedged on its gas and power requirements in this time frame. The Company expects to procure about 8,500 GWh of energy to serve our native load customers over the next 12 months through our own gas generation or from wholesale market purchases, and the price for over 7,000 GWh of this energy is already locked in. Thus, the impact on the Company's fuel expense is primarily due to the lower fuel prices on the unhedged 15%. In addition, the lower fuel and purchased power prices means that the Company's off-system sales decline by about $5 million. These two factors result in a net reduction to the Company's retail fuel expenses over the next 12 months of about $39 million.

Q. ARE YOU CONFIDENT THAT THESE FUEL EXPENSE REDUCTIONS WILL BE PERMANENT?

A. No, not at all. The amounts I have described are merely a snapshot of expected costs at a point in time. While I do not expect prices to move dramatically one way or another, I cannot predict what they will do. In fact, prices already have moved higher since I prepared these estimates. Furthermore, forward prices for 2007 are higher than those for 2006.

Q. WHAT IS THE IMPACT FROM THESE PRICE CHANGES ON THE COMPANY'S REQUEST?

A. The change to the Company's request is $67 million. The standard pro forma adjustment that is made to fuel expenses includes several normalizing adjustments, including those for planned maintenance at the Company's power plants, year-end customer and corresponding sales annualizations, and known and measurable changes in supply contracts. Although the Company is hedged at 85% for its anticipated gas and power needs in 2006, the hedged quantities are a lower share of the total in the standard pro forma adjustment. Therefore, the price declines have had a more material impact on the overall request than the Company will see in actual costs.

Q. YOU MENTION THE COMPANY'S CURRENT HEDGE POSITION. HOW DO THOSE HEDGE POSITIONS COMPARE TO CURRENT MARKET PRICES?

A. Even with the lower market prices, the Company's hedges are at prices lower than market by about $10 million. Thus, the reduction in market prices does not have any impact on about 85% of the Company's fuel expense because the Company locked in lower prices over the last two years.

Q. IS THE COMPANY'S PROJECTED FUEL EXPENSE IMPACTED BY THE UNPLANNED OUTAGES AT THE PALO VERDE NUCLEAR GENERATING STATION?

A. No. Instead, the amounts I discuss above assume normal operations for the Palo Verde Nuclear Generating Station ("Palo Verde") and the Company's other baseload plants for both the next 12 months' fuel expense projections and the standard pro forma expense calculation.

III. <u>STAFF AND INTERVENOR PROPOSALS LEAVE LARGE FUEL EXPENSE UNDER-COLLECTED BALANCES IN 2006</u>

Q. HAVE YOU CALCULATED THE IMPACT ON THE COMPANY FROM THE VARIOUS PROPOSALS BY STAFF AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION?

A. Yes. The following table summarizes the impact each of the proposals would have on the Company's under-collected fuel expense balance at the end of 2006 and the amount of recovery that occurs in 2006:

Proposal	2006 Year-End Balance (*$ millions*)	2006 Additional Revenue (*$ millions*)
ACC Staff	$ 255	$ 57
AECC	$ 174	$ 137
Staff Modified by APS	$ 241	$ 71
AECC and Staff Modified	$ 167	$ 144
APS Emergency Request	$ 113	$ 211

In order to provide an estimate of the impact of the Staff's proposal, I assumed that Staff provided a positive recommendation to the Commission within 30 days of the Company's quarterly filing and that such recommendation was implemented within the following 30 days. If those assumptions are correct, the Company would experience an increase in cash flow in 2006 of $57 million. The modifications to Staff's proposal described in Mr. Wheeler's testimony would provide an additional $14 million of fuel expense recovery relative to the Staff proposal. The AECC proposal described by Mr. Higgins provides $137 million of fuel expense recovery in 2006 and includes the first step of the Company's February 3, 2006 surcharge request plus $126 million. Combining AECC's proposal with the Company's proposed modifications of Staff's proposal as described in Mr. Wheeler's testimony provides an additional $7 million of fuel expense recovery relative to the AECC proposal. The Company's emergency request provides the greatest recovery of fuel expenses. In both the revenue recovery I describe here and the uncollected fuel expense balance I describe below, I have assumed for all of the proposals that the Commission approves both steps of the Company's February 3, 2006 surcharge application, although the second step does not yield any additional revenue in the AECC proposal.

Q. DOES THE COMPANY STILL HAVE A LARGE UNDER-COLLECTED FUEL EXPENSE BALANCE AT THE END OF 2006 UNDER ANY OF THESE PROPOSALS?

A. Yes. Setting aside the unrecovered balance in the 2006 Annual Adjustor Account (which will be approximately $12 million at 2006 year-end), the Company's emergency request manages to reduce the undercollection of fuel expenses to $113 million at the end of 2006. The balances in each of the other proposals are significantly larger, ranging from $167 million under the combination of the AECC proposal and the Company's modified Staff proposal to $255 million under the Staff proposal. These uncollected balances include the amounts remaining in the Surcharge Accounts at the end of 2006. That is, in both the Staff proposal and the APS modification to the Staff proposal, significant amounts of unrecovered fuel expenses will have been moved to the Surcharge Account and a relatively small balance will remain unaddressed in the Annual Tracking Account. The important point, though, is that the recovery under these two proposals begins very late in the year and provides much less help with the Company's 2006 financial condition. APS witnesses Steve Wheeler and Don Brandt discuss the impact of these recovery impacts on the Company's financials.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

<u>EXHIBIT 3</u>

ACC Decision No. 67744

April 7, 2005

BEFORE THE ARIZONA CORPORATION COMMISSION

21

Arizona Corporation Commission
DOCKETED

APR - 7 2005

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COMMISSIONERS

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437 DECISION NO. 67744 **OPINION AND ORDER**

DATES OF PROCEDURAL CONFERENCES:	August 13, 2003, January 6, February 18, April 7, 15, 28 May 26, June 14, August 18, and October 27, 2004
DATES OF HEARING:	November 8, 9, 10, 29, 30, December 1, 2, and 3, 2004
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Lyn Farmer
IN ATTENDANCE:	Marc Spitzer, Chairman William A. Mundell, Commissioner Jeff Hatch-Miller, Commissioner Mike Gleason, Commissioner Kristin K. Mayes, Commissioner
APPEARANCES:	Mr. Thomas L. Mumaw and Ms. Karilee S. Ramaley, PINNACLE WEST CAPITAL CORPORATION; Mr. Jeffrey B. Guldner and Ms. Kimberly Grouse, SNELL & WILMER, L.L.P., on behalf of Arizona Public Service Company; Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge; Mr. Patrick J. Black, FENNEMORE CRAIG, P.C., on behalf of Panda Gila River; Mr. S. David Childers, LOW & CHILDERS, P.C., Mr. James M. Van Nostrand, and Ms. Katherine McDowell STOEL RIVES, L.L.P., on behalf of Arizona Competitive Power Alliance; Mr. Lawrence V. Robertson, Jr., MUNGER

CHADWICK, on behalf of Southwestern Power Group II, Mesquite Power, and Bowie Power Station, LLC, and Mr. Theodore Roberts, SEMPRA ENERGY RESOURCES, on behalf of Mesquite Power;

Mr. Scott S. Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Walter W. Meek, President, on behalf of the Arizona Utility Investors Association;

Mr. Raymond S. Heyman, Ms. Laura E. Schoeler, and Ms. Laura Sixkiller, ROSHKA, HEYMAN & DeWULF, on behalf of UniSource Energy Services;

Major Allen G. Erickson on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of PPL Sundance and PPL Southwest Generation Holdings;

Mr. Nicolas J. Enoch, LUBIN & ENOCH, on behalf of the International Brotherhood of Electrical Workers;

Mr. William P. Sullivan and Mr. Michael A. Curtis, MARTINEZ & CURTIS, P.C., on behalf of the Town of Wickenburg, Arizona;

Mr. Bill Murphy, MURPHY CONSULTING and Mr. Douglas V. Fant, LAW OFFICES OF DOUGLAS V. FANT, on behalf of the Arizona Cogeneration Association;

Mr. Marvin S. Cohen, SACKS TIERNEY, P.A., on behalf of Constellation NewEnergy and Strategic Energy;

Mr. Andrew W. Bettwy and Ms. Karen S. Haller, on behalf of Southwest Gas Corporation;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, and Ms. Anne C. Ronan, on behalf of Western Resources Advocates and Southwest Energy Efficiency Project;

Mr. Jesse A. Dillon, on behalf of PPL Services Corporation;

Mr. Brian Babiars and Ms. Cynthia Zwick, WESTERN ARIZONA COUNCIL OF GOVERNMENTS, on behalf of Arizona Community Action Association;

Mr. Paul R. Michaud, MICHAUD LAW FIRM, on behalf of Dome Valley Energy Partners, LLC;

Mr. Michael L. Kurtz, BOEHM, KURTZ & LOWRY, on behalf of Kroger Company;

Mr. Christopher Kempley, Chief Counsel, Mr. Jason D. Gellman and Ms. Janet F. Wagner, Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

INDEX

BY THE COMMISSION:

I. DISCUSSION

On June 27, 2003, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase and for approval of a purchased power contract. The application states that the $175.1 million rate increase is needed to maintain the Company's credit ratings and attract new capital on reasonable terms, recover its cost of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service. The application requested that the Commission recognize the higher fuel and purchased power expenses being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC"); permit APS to recover the $234 million write-off taken under the 1999 Settlement Agreement; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq.* ("Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred. APS also requested approval of depreciation and amortization rates and a review of its long-term purchased power contract with PWEC if the assets are not rate based.

On July 25, 2003, the Utilities Division Staff ("Staff") of the Commission filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

By Procedural Order issued August 6, 2003, a Procedural Conference was scheduled for August 13, 2003, and intervention was granted to the Arizonans for Electric Choice and Competition ("AECC"), the Federal Executive Agencies ("FEA"), the Kroger Company ("Kroger"), the Residential Utility Consumer Office ("RUCO"), the Arizona Utility Investors Association, Inc., ("AUIA") and Phelps Dodge Corporation and Phelps Dodge Mining Company ("Phelps Dodge").

By various Procedural Orders, intervention was granted to: the International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Unions 387, 640 and 769 (collectively, "IBEW"), the Arizona Cogeneration Association/Distributed Generation Association of Arizona ("ACA" or "DEAA"), Panda Gila River, L.P. ("Panda"), Arizona Water Company ("AWC"), Southwest Gas Corporation ("SWG"), Western Resource Advocates ("WRA"), Constellation NewEnergy, Inc.

("CNE"), Strategic Energy, L.L.C. ("SEL"), Dome Valley Energy Partners, LLC ("DVEP"), UniSource Energy Services ("UES"), Arizona Community Action Association ("ACAA"), Arizona Competitive Power Alliance ("Alliance"), the Town of Wickenburg ("Wickenburg")[1], the Arizona Solar Energy Industries Association ("AriSEIA"), the Arizona Association of Retired Persons ("AARP"), Southwest Energy Efficiency Project ("SWEEP"), PPL Sundance, LLC ("PPL Sundance"), PPL Southwest Generation Holdings, LLC ("PPL Southwest"), Southwestern Power Group II, LLC ("SWPG"), Mesquite Power, LLC ("Mesquite") and Bowie Power Station, LLC ("Bowie").

On November 5, 2003, Staff filed a Motion to Consolidate ("Motion") the preliminary inquiry created by Decision No. 65796 and by Procedural Order the Motion was granted, authorizing Staff to include its report in this docket.

II. PRE-SETTLEMENT POSITIONS OF PARTIES

	APS	Staff	RUCO	Settlement Agreement
Revenue requirement	+\$175.1 M	-\$142.7 M	-\$53.6 M	+\$75.5 M
Return on Equity	11.5 %	9.0%	9.5%	10.25 %
Debt cost	5.8 %	5.8%	5.8%	5.8%
Capital Structure	50/50	55/45	55/45	55/45
Cost of Capital	8.67 %	7.3%	7.43%	7.8 %
PWEC assets	\$848 M	-	-[2]	\$700 M

III. SETTLEMENT AGREEMENT

a. Introduction

On August 18, 2004, a Settlement Agreement signed by 22 parties[3] was docketed with the Commission. AWC, SWG, and UES do not oppose the Settlement Agreement, and the AARP made public comment supporting it. The only party opposed to the Commission's adoption of the Settlement Agreement that presented testimony and evidence is the Arizona Cogeneration

[1] On August 18, 2004, Wickenburg moved to withdraw its intervention.
[2] Phase 1.
[3] APS, ACAA, Alliance, AECC, AriSEIA, AUIA, Bowie, CNE, DVEP, FEA, IBEW, Kroger, Mesquite, Phelps Dodge, PPL Southwest, PPL Sundance, RUCO, SWEEP, SWPG, Staff, SEL, and WRA.

Association/Distributed Generation Association of Arizona.[4]

APS' central objectives in settling were to preserve the company's financial integrity;[5] resolve the issue of asset "bifurcation"; and to determine the company's future public service obligations.

Staff believes that the Settlement Agreement is in the public interest because: it is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates; it is fair to the utility because it provides revenues necessary to provide reliable electric service along with an opportunity for a reasonable profit; the proposal balances many diverse interests including those of low-income customers, the renewable energy sector, Demand Side Management ("DSM") advocates, merchant generators, and retail energy marketers; it allows APS to rate base the PWEC assets, which are the generating plants originally built by APS' affiliate, PWEC, at a value that is significantly below their book value; potentially anti-competitive effects that may be associated with rate basing the PWEC assets are addressed through a self-build moratorium, a competitive solicitation in 2005, through workshops to address future resource planning and acquisition issues, and by adopting cost-based unbundling for generation and revenue cycle services in the rate design for general service customers, encouraging those customers to shop for competitive services; the Settlement Agreement resolves long, complex litigation by resolving issues associated with prior Commission decisions that are on appeal; the Settlement Agreement facilitates the provision of electric service at the lowest reasonable rates; it provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program; and because it includes a comprehensive DSM proposal intended to foster the development of new DSM programs while ensuring that the expenditures will be reasonable and subject to appropriate Commission oversight.[6]

RUCO noted that this rate case allowed sufficient opportunity for it to fully audit the Company's cost-of-service study and allowed all parties to be included in the negotiations. RUCO points to the very substantial, nearly universal consensus reached in the Settlement Agreement as

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[4] New Harquahala Generating Company, LLC and Panda made statements objecting to the rate basing of the PWEC assets.

[5] Defined as the ability to attract capital on reasonable terms and earn a reasonable return. Tr. p. 420.

[6] Summary of settlement testimony of Ernest Johnson.

indicating that the public interest has been served. According to RUCO, the "ultimate expression of the agreement having met the Public Interest is the degree to which rate increases have been minimized without jeopardizing the financial integrity of the applicant."[7]

The Alliance's central objective is to continue towards a viable and effective wholesale market into which Alliance members can sell their power. According to the Alliance, there are several key provisions in the Settlement Agreement that accomplish that goal: the restrictions on self-build coupled with the high growth rate in APS' service territory; and the 1,000 megawatt Request for Proposal ("RFP") in 2005. The Settlement Agreement also preserves the financial stability and creditworthiness of the Alliance's target customer – APS.[8]

b. **Revenue Requirements**

For ratemaking purposes and for purposes of the Settlement Agreement, the parties agree that APS will receive a total increase of $75.5 million over its adjusted 2002 test year ("TY") revenue of $1,791,584,000. This represents an increase in base rates of $67.6 million and a Competition Rules Compliance Charge ("CRCC") surcharge collecting $7.9 million. Pursuant to the Settlement Agreement filed on August 18, 2004, as corrected in the hearing, the Company's fair value rate base ("FVRB") is $5,054,426,000.[9] According to the Settlement Agreement, this revenue increase will allow the Company the opportunity to earn a fair value rate of return of 5.92 percent. According to the Company and Staff, the revenue requirement contained in the Settlement Agreement provides sufficient revenues for APS to provide adequate and reliable service.[10]

c. **PWEC Asset Treatment**

The Settlement Agreement provides that APS will acquire and rate base generation units owned by PWEC.[11] Those units include: West Phoenix CC-4; West Phoenix CC-5; Saguaro CT-3; Redhawk CC-1; and Redhawk CC-2 ("PWEC assets"). Pursuant to the Settlement Agreement, the

[7] Summary of settlement testimony of Stephen Ahearn.
[8] Tr. p. 458.
[9] Paragraph 4 to the Settlement Agreement states the FVRB is $6,281,885,000, however, during the hearing, that amount was corrected to $5,054,426,000. Tr. p. 692.
[10] Tr. p. 810.
[11] On November 10, 2004, PWEC filed a letter with the Commission indicating that it would abide by the provisions of the Settlement Agreement that require PWEC to take or refrain from taking any action in order to carry out the intent of the Settlement Agreement.

original cost rate base ("OCRB") of the PWEC assets will be $700 million which is $148 million less than the original cost of the assets as of December 31, 2004. According to the Settlement Agreement, this represents a reasonable estimate of the value of the remaining term of the Track B contract between APS and PWEC.[12] APS agrees to forgo any present or future claims of stranded costs associated with these PWEC assets. According to the Settlement Agreement, APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS agreed to file a request for FERC approval within 30 days of the Commission's approval of the Settlement Agreement, and the parties have agreed not to oppose the FERC application. The Settlement Agreement provides for a bridge purchased power agreement ("Bridge PPA") to be implemented once new rates are put in place, until the actual date of the transfer of assets. APS and PWEC will execute a cost-based PPA which will be based on the value of the PWEC assets, and fuel costs and off-system sales revenue will flow into the power supply adjustor ("PSA"). If FERC denies the asset transfer, then the Bridge PPA will become a 30 year PPA, with prices reflecting cost-of-service as if the PWEC assets were rate-based at the $700 million amount in the Settlement Agreement, and with the associated fuel costs and off-system sales revenue flowing through the PSA. The basis point credit established in Decision No. 65796 will continue as long as the debt between APS and PWEC associated with the PWEC assets is outstanding. Credit for amounts deferred after December 31, 2004 will be accounted for in APS' next rate case. The Settlement Agreement also provides that West Phoenix CC-4 and West Phoenix CC-5 will be deemed "local generation" and during must-run conditions, generation from the West Phoenix facilities will be available at FERC-approved cost-of-service prices to electric service providers ("ESPs") serving direct access loads in the Phoenix load pocket.

Treatment of the PWEC assets requires not only a regulatory ratemaking type analysis, but also an analysis of how rate basing these assets fits with the Commission's overall plan for wholesale and retail electric competition in Arizona.

For the last ten years, the Commission has studied, discussed, and deliberated about electric

[12] Docket Nos. E-00000A-02-0051 et al.

competition through workshops, rulemakings, hearings, and open meetings. Several versions of electric competition rules have been adopted, and litigation concerning Commission decisions has been conducted. Throughout this time, the Commission has always maintained its intent to encourage competition in the electric industry. In the wake of the California energy crisis the Commission opened dockets to examine changing industry and market conditions and introspectively analyzed their impact on Arizona's existing rules. The Commission reacted in a measured manner to flawed rules in other jurisdictions and corrected, but did not change, its course.

The Commission continues to support competition as yielding economic and environmental benefits to Arizona consumers. The $148,000,000 discount from book for the rate-based PWEC assets is indicative of these benefits. Recent transactions reflected in the record, including below-cost sales, foreclosures and bankruptcies, establish that the shareholders of the power plants' builders absorbed the costs and bore the brunt of a declining market, rather than Arizona ratepayers. The discounted conveyance of the PWEC assets to APS is further support for this proposition. APS' request and the Settlement Agreement's provision allowing APS to acquire the PWEC assets and put them in rate base raises the issue of whether such action would undermine the Commission's stated intent to encourage retail and wholesale competition. The terms of the Settlement Agreement taken as a whole indicate to us that the answer to that question is "no".

During the hearing on the Settlement Agreement, the parties presented evidence demonstrating that the PWEC acquisition was the most beneficial option for ratepayers. Staff testified that the responses to APS' last formal RFP did not indicate to Staff that the market would provide a superior alternative to the rate basing of the PWEC assets. The testimony indicates that growth in APS' service territory is a minimum of 3 percent per year. APS argued that even with rate basing the PWEC assets, APS' needs would not be met, and it would have to procure additional power to meet the needs of its customers. The Settlement Agreement provides that APS will issue an RFP for an additional 1000 megawatts, thereby giving other market participants an opportunity to compete. The organization created to represent the interests of the merchant community, the Alliance, supports the transfer of assets, because it believes that resolving the broader issues of overall market structure, the self-build guidelines and future RFPs, together with the reduction in litigation risk will further its overall goal of promoting a viable and effective wholesale market. The key provision that the Alliance relies on is the 1,000 megawatt RFP in 2005 that provides a degree of certainty regarding the timing of an initial increment of APS' future needs to be met from the wholesale market. Also, the Alliance believes that opportunities will exist for its members because of the self-build limitation and the high growth rate in Arizona. The proponents of retail competition also support the asset transfer; in large part because APS agrees to forgo any present or future claims of stranded costs associated with the PWEC assets, because rates are unbundled, and because of the treatment of the West Phoenix facilities.

We believe that nothing in the Settlement Agreement prevents the continued development of electric competition. Any potential anti-competitive effects of the asset transfer will be addressed through the competitive solicitations, the self-build moratorium,[13] and Staff's workshops to address future resource planning and acquisition issues. As discussed below, the evidence indicates that the asset transfer captures the benefit of the competitive procurement that took place as a result of the Track B proceeding.

The original cost of the PWEC assets at December 31, 2004 was $848 million. Traditionally, when a utility builds plant, unless there is a finding of imprudency, that portion of the plant that is used and useful is put into rate base and the utility is allowed an opportunity to earn a reasonable rate of return on that investment. This situation is different from the traditional rate case. APS did not build the PWEC assets; they were built by APS' affiliate during a time when the Commission intended APS to divest itself of generation. During the proceeding on APS' financing application, concern was raised that APS and its affiliates took actions that gave it an unfair advantage as compared to its potential competitors. In Decision No. 65796, which granted APS' financing request, we directed Staff to conduct a preliminary inquiry into the issue of APS and its affiliate's compliance with our electric competition rules, Decision No. 61973, and applicable law. The Settlement Agreement provides that the preliminary inquiry will be concluded with no further action by the

[13] Neither APS nor PWEC will build the Redhawk Units 3 & 4. PWEC's February 2003 self-certification filing with the Commission stated that the two remaining units pursuant to its Certificate of Environmental Compatibility ("CEC") would not be built. Tr. pp. 594-5.

Commission. Accordingly, we make no finding as to why or for whom the PWEC assets were built, and base our resolution of the rate basing issue solely on the merits of the terms of acquisition. We believe that if there were a serious threat to competition, we would hear from those affected, loudly and strongly. Therefore, we were keenly interested in the position of the members of the Alliance, as they are one type of entity that could be harmed. The Alliance supports the acquisition of the PWEC assets by APS. Every person or entity that will be affected by the rate basing of the PWEC assets had the opportunity to participate and present evidence and testimony on this issue. Although two independent power producers made comments objecting to the acquisition without an RFP, neither presented any evidence that demonstrated that competition would be harmed, nor rebutted the testimony and evidence concerning APS' recent RFP.

Initially Staff recommended that the PWEC assets not be rate based, but after analyzing the Company's rebuttal testimony and evidence, agreed that a reduction of $148 million in original cost rate base made the acquisition beneficial to ratepayers. The evidence in the record is substantial that APS' analysis of other options versus rate basing PWEC assets showed that: using an "other build" analysis, rate basing the PWEC assets would cost $300-600 million less than cost to build other plants such as Combustion Turbines ("CT"); using a comparable sales analysis showed that other recent sales had a per kW cost in excess of $527 and the PWEC assets are at $417; when compared to the offers resulting from the recent RFP conducted by APS, the PWEC assets (when valued at the before discount $848 million level) showed benefits of $600-900 million; and using a discounted cash flow analysis the PWEC assets had a savings of $250 million to $1 billion.

As part of the settlement, APS agreed to reflect an original cost rate base value of $700 million, representing a $148 million disallowance. The effect of a reduction in rate base is to immediately reduce the revenue requirement, and to preserve that diminished revenue requirement for the life of the plant.

The analyses showing that the rate basing of the PWEC assets will result in lower rates than other options, together with no showing that such an acquisition would harm the development of a competitive wholesale or retail market indicate that it is reasonable and in the public interest for APS to acquire and rate base the PWEC assets as set forth in the Settlement Agreement.

d. **Cost of Capital**

The Settlement Agreement adopts a capital structure of 55 percent long-term debt and 45 percent equity for ratemaking purposes. The parties agree that a 10.25 percent return on common equity and a 5.8 percent embedded cost of long-term debt is appropriate.

e. **Power Supply Adjustor (PSA)**

The Settlement Agreement provides that a PSA be implemented and remain in effect for a minimum of five years, with reviews available during APS' next rate case, or upon APS' filing its report on the PSA four years after rates are implemented in this rate case. Regardless of the review/report, the PSA cannot be abolished until five years have expired. The Settlement Agreement provides that APS will file a plan of administration as part of its tariff filing that describes how the PSA will operate. According to the Settlement Agreement, the PSA will have the following characteristics:

- Includes both fuel and purchased power;
- The adjustor rate will initially be set at zero and will thereafter be reset on April 1 of each year, beginning with April 1, 2006. APS will submit a publicly available report on March 1 showing the calculation of the new rate, which will become effective unless suspended by the Commission;
- Incentive mechanism where APS and its customers share 10 percent and 90 percent, respectively, the costs and savings;
- Bandwidth that limits annual change in adjustor of plus or minus $0.004 per kilowatt hour, with additional recoverable or refundable amounts recorded in balancing account;
- Surcharge possible if balancing account reaches plus or minus $50 million and Commission approves;
- Off-system sales margins credited to PSA balance;
- Recovery of prudent, direct costs of contracts for hedging fuel and purchased power costs;
- Interest on balancing account will accrue based on the one-year nominal Treasury constant maturities rate;
- The Commission or its Staff may review the prudence of fuel and power purchases at any

time;

- The Commission or its Staff may review any calculations associated with the PSA at any time; and
- Any costs flowed through the adjustor are subject to refund if the Commission later determines that the costs were not prudently incurred.

The Settlement Agreement provides that APS shall provide monthly reports to Staff's Compliance Section and to RUCO detailing all calculations related to the PSA, and shall also provide monthly reports to Staff about APS' generating units, power purchases, and fuel purchases. An APS officer must certify under oath that all the information provided in the reports is true and accurate to the best of his or her information and belief. The Settlement Agreement also provides that direct access customers and customers served under rates E-36, SP-1, Solar-1, and Solar-2 are excluded from paying PSA charges. Under the Settlement Agreement, the PSA remains in effect for 5 years, and if after that, the Commission abolishes the PSA, it must provide for any under- or over-recovery and can adjust base rates to reflect costs for fuel and purchased power. The parties agree that a base cost of fuel and purchased power of $.020743 per kWh should be reflected in APS' base rates.

Decision No. 61973 (October 6, 1999) adopting the previous APS settlement, required APS to request, and the Commission to approve, a "power supply adjuster" mechanism to recover the cost of providing power for standard offer and/or provider of last resort customers.

In Decision No. 66567 (November 18, 2003), the Commission approved the concept of a Purchased Power Adjustor ("PPA") which included purchased power costs and did not include the cost of fuel. The Decision noted that the adjustor mechanism approved therein may be modified or eliminated in this rate case. As noted in that Decision, there are advantages and disadvantages to adjustor mechanisms:

Advantages: 1) the reporting requirements and forecasts facilitate utility planning and Staff overview of costs; 2) an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates; 3) adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included; 4) adjustors can help reduce the frequency of rate cases; 5) regulatory lag between the incurrence of an expense and its recovery is reduced and generational inequities are also reduced.

Disadvantages: 1) adjustors can reduce incentives to minimize costs; 2) an adjustor that includes fuel or purchased power costs potentially biases capital investment decisions towards those with lower capital costs and higher fuel costs; 3) adjustors create another layer of regulation to rate cases, increasing the cost of regulation to the utility, its customers, and to the Commission; 4) an adjustor can shift a disproportionate proportion of the risk of forced outages and systems operations from shareholders to ratepayers; 5) adjustors result in piecemeal regulation – an adjustor reflects an increase in one expense but ignores offsetting savings in other costs; 6) adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers; 7) proper monitoring of adjustor filings and audits require the devotion of significant Staff resources; and 8) rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Although we recently approved the concept of a PSA, we are concerned about the PSA as proposed in the Settlement Agreement. The benefits of this PSA are that over time, the utility's earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers. Further, as part of the negotiations, the parties were able to agree on a lower overall revenue increase because a PSA was to be implemented. AECC pointed out that if an adjustor remains in effect for long enough, it becomes a credit, and therefore, the PSA should remain in effect for five years.[14]

The disadvantages are real and significant – from a customer standpoint, adjustors are difficult to understand and they can cause annual price increases. From a regulatory standpoint, they require significant Commission staff resources to properly monitor filings, costs, and compliance and to respond to consumer inquiries and complaints. The most significant change that will occur with a PSA is the shifting of the risk that fuel costs will increase above the base rates established in the Settlement Agreement. Currently, if fuel costs or any other costs rise above the level embedded in

[14] Tr. p. 1249.

the existing rate structure, the company's shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS' "mix" of fuel will change as growth occurs.[15] That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS' other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a *high cost fuel.*[16]

Although the Settlement Agreement provides that APS will increase its demand side management and renewables, and we agree that those resources are increasingly important, they will not likely have a significant ameliorating cost impact in the near future. We disagree with the parties that a 90/10 sharing is sufficient incentive for APS to continue to effectively hedge its natural gas costs. Going from a 100 percent at-risk position to 10 percent at-risk almost seems like a "free pass," especially when a revenue increase is added. Although the Settlement Agreement provides that all costs will be subject to review for prudency before they can be recovered, prudency reviews, especially transactions in the wholesale market, can be difficult to conduct after the fact. Although we have confidence in our Staff's ability to conduct prudency reviews, we do not believe they provide as much incentive to APS on the front end to hedge costs as exists today without a PSA. The band-width limit will help limit drastic increases, but ultimately, APS will be able to recover all the costs from ratepayers.[17]

Accordingly, for these reasons, we believe that provisions of the PSA need to be modified to protect the ratepayers. We agree that the use of an adjustor when fuel costs are volatile prevents a

[15]As growth occurs, the per unit cost of fuel will increase. Tr. p. 1238. Currently, nuclear is 32 percent of sales and represents 7.4 percent of the costs of generation; coal is 45 percent of sales and 29.7 percent of generation costs; natural gas is 18 percent of sales and 47.4 percent of generation costs; and purchased power is 5 percent of sales and 15.5 percent of generation costs. Tr. p. 1257. In five years, natural gas is expected to be 29-30 percent of sales. TR. p. 1258.

[16] See discussion Tr. p. 1259, PSA will always be increasing.

[17] Staff's late-filed exhibit S-35 filed December 14, 2004 in response to a request from Commissioner Mundell to extrapolate the effects of the PSA over several years, contained an error and on March 9, 2005, Staff filed a corrected exhibit.

utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

Further, we will limit the amount of "annual net fuel and purchased power costs" (as shown in Staff Exhibit 23)[18] that can be used to calculate the annual PSA to no more than $776,200,000. Any fuel or purchased power costs above that level will not be recovered from ratepayers. We believe that this "cap" on fuel and purchased power costs will further encourage APS to manage its costs, and will help to prevent large account balances from occurring in one year. Because the PSA actually adjusts for growth, putting a "cap" on recovery of these costs will help insure that APS will file a rate application when necessary.[19] Since there is no moratorium on filing a rate case, APS can file a rate case to reset base rates if it deems it necessary because that cap is reached. Further, although the Settlement Agreement provides that the PSA will be in effect for 5 years, if APS files a rate case

[18] For example, under "Average Usage Scenario One", the line reads "Annual Net Fuel and Purchased Power Costs: $524,600,000."

[19] See S-35 filed March 9, 2005, Scenario 11A – even when the price of gas remains constant, the PSA adjustor increases, because the adjustor uses total costs (not price) which reflects the growth which is being met by the higher priced fuel, natural gas.

prior to the expiration of that 5 year term or if we find that APS has not complied with the terms of the PSA, we believe that the Commission should be able to eliminate the PSA if appropriate. Finally, we will not allow any fuel costs from 2005 that were incurred prior to the effective date of this Decision to be included in the calculation of the PSA implemented in 2006. We believe that these additional provisions to the PSA will help to lessen the detrimental impact to ratepayers of this change to an adjustor mechanism.

Implementing an adjustor mechanism will have a significant impact upon both APS and its customers. For many years now, in their monthly bills, APS customers have paid rates that reflect the costs that APS is allowed to recover for providing that service. With the implementation of an adjustor, those ratepayers will be obligated to pay additional amounts for service they received in the previous year. This represents a major shift in responsibility for increased costs, from APS and its shareholders to ratepayers. According to APS, such a shift is necessary for the company to preserve its financial integrity.

Although the parties submitted a written statement describing the calculation of off-system sales in response to a question from Commissioner Mundell, we are concerned that the method may not capture the full margin on each sale.[20] Additionally, we want to make sure that off-system sales are not being made below costs – Staff needs to study ways to insure that these off-system sales margins are being determined accurately and that ratepayers are receiving the full 90 percent of the benefits. Accordingly, we will direct Staff to establish a method that accurately reflects the appropriate fuel costs and revenue for off-system sales, so that the full margin is known and properly accounted for. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

In response to Commissioner Gleason's suggestion to set up a webpage explaining its bill, APS indicated that it was planning to have a new bill format, and agreed to also set up a website to

[20] For example, a wholesale contract may have an embedded cost of fuel built into the price of the energy that is different from the cost of fuel use to generate the energy – if the "sales margin" is defined as the difference between the actual cost of fuel and the revenue from the sale, the true sales margin will not be captured. We also take administrative notice of FERC Docket No. PA04-11-000 and the FERC's December 16, 2004 Order Approving Audit Reports and Directing Compliance Actions, specifically relating to treatment of off-system sales.

explain the bills. Because the implementation of an adjustor will be a major change in the way that customers are billed, we believe that APS should also implement a customer education program explaining how its PSA will work and we will order APS to maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. It is important that the customer education program be implemented in a timely fashion, before this summer. APS needs to make its customers aware that with the implementation of an adjustor, ratepayers will be obligated to pay additional amounts for service they received in the previous year. It is essential, and only fair, that customers understand that their usage this summer can have an effect on their electric bills the following year.

Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program. Finally, given our concerns and the modifications we require to the PSA, we will require the parties to the Settlement Agreement to submit a PSA Plan of Administration that reflects the determinations in this Decision, for our approval.

f. Depreciation

The Settlement Agreement adopts Staff's recommended service lives, and Appendix A to the Settlement Agreement sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property as agreed to by the parties. The parties agree that the Statement of Financial Accounting Standards ("SFAS") 143 will not be adopted for ratemaking purposes.

g. $234 Million Write-Off

The Settlement Agreement provides that APS will not recover the $234 million write-off attributable to Decision No. 61973 in this case, nor shall APS seek to recover the write-off in any subsequent proceeding. The ESP and large consumer witnesses testified that this provision was critical to the development of flourishing retail markets and will help direct access service from being undercut by future stranded costs claims.

h. Demand Side Management ("DSM")

Demand-side management ("DSM") is "the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner."[21]

DSM is addressed in three areas of the Settlement Agreement: in the funding, programs, plans and reporting provisions; in the study of rate design modifications; and in the competitive procurement process.

Funding for DSM comes in both base rates ($10 million per year) and through implementation of an adjustor (average of $6 million per year).[22] DSM funding will be used for "approved eligible DSM-related items," including "energy-efficiency DSM programs,"[23] a performance incentive,[24] and low income bill assistance.[25] APS is obligated to spend $13 million in 2005 on DSM projects.[26]

Appendix B to the Settlement Agreement is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for 2005. The Preliminary Plan includes $6.9 million for commercial, industrial, and small business customer programs, including new construction, retrofitting existing facilities, training and education, design assistance, and financial incentives; it includes $6.2 million for residential customers, including new construction and existing homes and HVAC, education, training, expanded low income weatherization, and bill assistance; $1.3 million for measurement, evaluation, and research; and $1.6 million for performance incentive.[27] Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative working group, submit a Final Plan for Commission approval.

In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

The adjustor will collect DSM costs that are above the $10 million annual level included in

[21] Direct testimony of Barbara Keene, February 3, 2004.
[22] APS will spend at least $48 million during calendar years 2005-2007.
[23] "Energy-efficient DSM" is defined as "the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices." Settlement Agreement par. 40.
[24] Id. par. 45.
[25] Id. par. 42.
[26] Tr. p. 969.
[27] APS' share of DSM net economic benefits, capped at 10 percent of total DSM expenditures.

base rates. The adjustor rate will initially be set at zero, and will be adjusted yearly on March 1, based upon the account balance and the appropriate kWh or kW charge. The DSM adjustor will apply to both standard offer and direct access customers.

The Settlement Agreement does not provide for the recovery of net lost revenues. The Settlement Agreement provides that if during 2005 through 2007, APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items; the unspent amount will be credited to the account balance for the DSM adjustor.

On residential customers' bills, the DSM adjustor will be combined with the EPS adjustor and be called an "Environmental Benefits Surcharge."[28] As part of its tariff compliance filing, within 60 days of this Decision, APS must file a Plan of Administration for Staff review and approval.

Pursuant to the Settlement Agreement, APS is required to "implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance."[29] The working group will review the plans, but APS is responsible for demonstrating appropriateness of its programs to the Commission. APS is required to conduct a study to review and evaluate whether large customers should be allowed to self-direct DSM investments and file the study within one year. APS is also required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand. The plan for the study and analysis of rate design modifications must be presented to the collaborative DSM working group within 90 days, and APS must submit to the Commission the final results as part of its next rate case, or within 15 months of this Decision, whichever is first. APS is required to develop and propose appropriate rate design modifications. Additionally, APS is required to file mid-year and end-year reports on each DSM program. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

Pursuant to the Settlement Agreement, APS is to invite DSM resources to participate in its RFP and other competitive solicitations, and must evaluate them in a consistent and comparable

[28] Settlement Agreement par. 50.
[29] Id. par. 54.

manner.

SWEEP supports the DSM provisions in the Settlement Agreement. Although it originally recommended that the Commission should substantially increase energy efficiency by setting target goals of 7 percent of total energy resources needed to meet retail load in 2010 from energy efficiency and 17 percent in 2020, it agreed that the Settlement Agreement's requirement of DSM funding is reasonable and justified given the cost-effective benefits that will be achieved. SWEEP believes that the level of funding in the Settlement Agreement is a valuable and meaningful step towards encouraging and supporting energy efficiency for APS customers, especially since the Commission can approve additional DSM program funding through the adjustment mechanism.

In response to questioning from Commissioner Spitzer, the witness for SWEEP testified that DSM is the most efficient way to mitigate market and fuel price increases and it reduces customer vulnerability to price volatility, by reducing the need for new power plant construction and new transmission lines.[30] Even customers who do not participate in the DSM programs will benefit, both from an economic perspective as well as from the environmental and health standpoint.[31] The Preliminary DSM Plan attached as Exhibit B to the Settlement Agreement is a good start towards developing cost-effective DSM programs. However, we are concerned that our approval of the Settlement Agreement and Exhibit B may result in stakeholders focusing too narrowly when attempting to comply with the DSM goals of this Order. Particularly, we note that there are no demand response programs included in Exhibit B. Given the response by APS' customers to last summer's outage as discussed by Commissioner Hatch-Miller,[32] it is clear that when proper signals are given, customers will respond by reducing their demand.

We also think it is clear that the traditional demand response programs that define "off-peak" hours as between 9:00 p.m. to 9:00 a.m. are ineffective in creating an incentive to residential ratepayers to shift their electricity consumption to "off peak" hours. Common sense indicates that a substantial number of ratepayers cannot or are not able to take advantage of such programs as 9:00 p.m. is an unrealistic time to commence the "off peak" period because most ratepayers are either

[30] Tr. p. 877.
[31] Tr. p. 930.
[32] See discussion Tr. pp. 1384-1394.

asleep or preparing to sleep at that time.[33] Further, the start time begins many hours after the actual peak has subsided. Finally, the inconvenience of a 9:00 p.m. start time assures that the demand response to "off peak" hours and programs is miscalculated. Therefore, in an effort to expedite APS' addressing demand response programs, we will order APS to file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

We believe that it would be beneficial, perhaps in conjunction with the rate design time-of-use study and the use of "advanced" or "smart" meters, to evaluate and implement programs designed to reduce APS' summer peak demand. Accordingly, we will encourage submission of such DSM programs.

i. <u>Environmental Portfolio Standard and other Renewables Programs</u>

The Settlement Agreement addresses renewable energy in three areas: a special renewable energy solicitation; the environmental portfolio standard ("EPS") and in the competitive procurement of power.

The Settlement Agreement requires APS to issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of renewable energy resources including solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas) or geothermal for delivery beginning in 2006. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005. APS also will seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. Among other requirements, the renewable resources must be no more costly than 125 percent of the reasonably estimated market price of conventional resource alternatives and APS can acquire out-of-state resources to meet the goal if sufficient in-state qualified bids are not received. However, if APS determines that it cannot meet this requirement through in-state resources, it must bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

[33] We do not need a study, workshop or to evaluate the proposed test demand programs to convince us regarding residential demand programs in this matter.

The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

The special RFP does not displace APS' requirements under the EPS. APS will continue to collect $6 million annually in base rates and the existing EPS surcharge, which provided $6.5 million during the test year, will be converted to an adjustment mechanism, which will allow for Commission-approved changes to APS' EPS funding.

The Settlement Agreement does not alter the existing EPS or the current level of funding, but it changes the EPS surcharge into an adjustor so that the Commission has the flexibility to change funding levels and rates in the future. APS' current rates and surcharge total $12.5 million and pursuant to the Settlement Agreement, $6 million of this amount will be recovered in base rates and $6.5 million in the EPS adjustor.

Under the Settlement Agreement, APS will allow and encourage all renewable resources to participate in its competitive power procurement.

In response to a request from Commissioner Spitzer, several parties filed late-filed exhibits concerning the recently enacted American Jobs Creation Act of 2004. According to APS, the Act provides for a domestic production deduction for its generation activities, and also extends renewable electricity production credits through 2005 and expands the types of renewable resources eligible for the credits.[34] In its December 10, 2004 response, WRA stated that "renewable energy appears to be at a disadvantage relative to gas-fired generation because the tax burden tends to fall more heavily on capital intensive projects such as renewable energy generation. Therefore, such tax burden differentials may add further support for the preference for renewable energy in the settlement agreement and for production tax credits as means to 'level the playing field' between gas-fired

[34] Previously, only wind, closed-loop biomass and poultry waste were included, and now open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste are included as qualified energy resources.

resources and renewable energy."

j. Competitive Procurement of Power

The Settlement Agreement provides that APS will issue an RFP or other competitive solicitation(s) in 2005 seeking long-term resources of not less than 1000 MW for 2007 and beyond. "Long-term" resource is defined as acquisition of a generating facility or an interest in one, or any PPA of 5 years or longer. No APS affiliate will participate in this RFP/solicitation, and in the future will not participate unless an independent monitor is appointed. Further, APS will not self-build any facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. As defined in the Settlement Agreement, "self-build" does not include the acquisition of a generating unit or interest in one from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than 50 MW per location, renewable resources, or the up-rating of APS generation.

We generally agree that the self-build moratorium proposed in the Agreement is useful for addressing the potentially anti-competitive effects that may be associated with rate-basing the PWEC assets. However, to fully realize the benefits of the moratorium for that purpose, the moratorium should apply to the acquisition of a generating unit or interest in one from any merchant or utility generator, as well as to building new units. Accordingly, we will modify the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator. Consistent with the definition in the Settlement Agreement, "self-build" will not include the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or up-rating of APS generation, which up-rating shall not include the installation of new units.

Similarly, we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation[35] issued before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to

[35] Competitive solicitation includes a RFP issued pursuant to Paragraph 78 of the Settlement Agreement or any solicitation issued by APS in using its Secondary Procurement Protocol pursuant to Paragraph 80 of the Settlement Agreement.

any generating facility or interest in any generating facility ultimately acquired by APS. APS will continue to use its Secondary Procurement Protocol except as modified by the Settlement Agreement or by Commission decision. The Commission's Staff will schedule workshops on resource planning, focusing on developing needed infrastructure and a flexible, timely, and fair competitive procurement process. As discussed above, the rate basing of PWEC assets, at a discount, should not be construed as an abandonment of competition by this Commission. The industry-wide question, "how will new generation be built and by whom?", is particularly trenchant in Arizona due to high forecast growth in customer load. The self-build moratorium agreed to by APS is consistent with the Commission's support for competitive wholesale electricity markets.

The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

By integrating solar generation with the existing generation and transmission infrastructure at coal fired facilities, it may be possible to create synergies that take advantage of existing site infrastructure to lower the cost of building and operating solar electric generation, while reducing the environmental impact of coal fired generation. Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy specific water usage. A long-term benefit of such a strategy would be that after all life extension measures are exhausted for the fueled power complexes, there will be many decades of useful life remaining in the transmission assets serving these sites. These valuable assets could be utilized by emission and water free solar generation built incrementally over the next decades in the expansive buffer zone property around many of the existing coal plants.

k. **Regulatory Issues**

In the Settlement Agreement, the parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area and to recognize through its planning, the existence of any Commission direct access program and the potential for future direct access customers. Any change in retail access as well as the resale by APS and other Affected Utilities of Revenue Cycle Services to ESPs will be addressed through the Electric Competition Advisory Group ("ECAG") or similar process. The parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or entity and may participate in those activities without further order or authorization from the Commission.

l. Competition Rules Compliance Charge ("CRCC")

Included in the total test year revenue requirement is approximately $8 million for the Competition Rules Compliance Charge. APS will recover $47.7 million plus interest through a CRCC of $0.000338/kWh over a collection period of 5 years. When that amount is collected, the CRCC will immediately terminate, and if the amount is under or over recovered, then APS must file an application for the appropriate remedy.

m. Low Income Programs

APS will increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000 as set forth in the Settlement Agreement. The parties' intent is to insulate eligible low income customers from the effects of the rate increase resulting from the Settlement Agreement. On December 17, 2004, the ACAA filed a response to Commissioner Mayes' question about automatic enrollment in utility discount programs, indicating that they have initiated a discussion with the Arizona Department of Economic Security ("DES") to facilitate the automatic enrollment in utility discount programs, as well as other agency managed programs. ACAA is in the process of adding the utility discount application forms to its website, which will allow the form to be sent electronically to the appropriate entity for processing. Concerning marketing efforts, ACAA stated that it engages in various outreach efforts throughout the state, providing information about the E-3 discount program available through APS. ACAA indicated that DES is currently charged with the official marketing of the program, but there is currently no affirmative marketing of the program "as their resources are severely limited." Also in response to Commissioner Mayes' request, APS filed information concerning its low income programs. APS stated that it has renewed its conversations with DES and ACAA, requesting feedback on increasing participation through automated signup for the E-3 and E-4 programs. Both agencies expressed interest and APS states that it will continue to work with both agencies to determine the efficiency and practicality of such a streamlined approach.

The Commission believes that APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

n. Returning Customer Direct Access Charge ("RCDAC")

The Settlement Agreement provides that APS can recover from Direct Access customers the additional cost that would otherwise be imposed on other Standard Offer customers if and when the former return to Standard Offer from their competitive suppliers. The RCDAC shall not last longer than 12 months for any individual customer. The charge will apply only to individual customers or aggregated groups of 3 MW or greater who do not provide APS with one year's advance notice of intent to return to Standard Offer service. APS will file a Plan of Administration as part of its tariff compliance filing.

o. Service Schedule Changes

The Settlement Agreement adopts several of APS' proposed changes to service schedules, including Schedule 3, but with the retention of the 1,000 foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Several APS customers made public comment about the line extension policy and how it has not been modified in a long time. We will direct Staff to work with APS to review its line extension policy and determine whether the construction allowance should be modified.

p. Nuclear Decommissioning

The decommissioning costs as recommended by APS are adopted as set forth in Appendix I to the Settlement Agreement.

q. Transmission Cost Adjustor ("TCA")

The Settlement Agreement establishes a transmission cost adjustor ("TCA") to ensure that any potential direct access customers pay the same for transmission as Standard Offer customers.

The TCA is limited to recovery of costs associated with changes in APS' open access transmission tariff ("OATT") or equivalent tariff. The TCA goes into effect when the transmission component of retail rates exceeds the test year base amount of \$0.00476[36] per kWh by 5 percent and APS obtains Commission approval of a TCA rate.

r. **Distributed Generation**

Generally, distributed generation is small-scale power generation units strategically located near customers and load centers. According to the ACA/DEAA, the benefits of distributed energy systems include: greater grid reliability; increased grid stability (voltage support along transmission lines); increased system efficiency (reduction in transmission line losses); increased efficiency; flexibility; decreased pressure on natural gas (demand and cost); leverage of resources; and sustainable installations.

The Settlement Agreement provides that Staff shall schedule workshops to consider outstanding issues affecting distributed generation and shall refer to the results of the prior distributed generation workshops for issues to study.

ACA/DEAA presented its objectives at hearing as follows: a DG workshop with strong Staff leadership; clear goals, ground rules, milestones, and deadlines; participants with authority; continuing reports to ACC and management; and a process to bring contested issues to the Commission for resolution. None of the proponents of the Settlement Agreement oppose Commission adoption of these objectives.

In its post-hearing brief, ACA/DEAA listed the following guidelines as "overriding criteria": 1) rates must be fair; 2) rates should be designed to send as efficient as possible pricing signals to consumers; 3) impediments to customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible; 4) all generators should be treated fairly – large and small; and 5) proposals, if implemented, should not interfere with the Commission's public policy goals. ACA/DEAA made 3 recommendations: 1) Rate Design – the Commission should adopt an experimental rate for partial requirement customers. The proposal

[36] Paragraph 106 of the Settlement Agreement contains a typo; the amount "\$0.000476" should actually be "\$0.00476," Tr. p. 1168.

would mimic SRP's E-32 rate, which includes time of day rates and summer/winter rates. ACA/DEAA proposed to limit participation to 50 MWs of new customer load each year for 5 years – both generation and supplemental load. It appears that this is the first alternative rate schedule that ACA/DEAA has proposed, and no party has had an opportunity to evaluate and comment on the proposal. Accordingly, we decline to adopt the proposal in this docket, but we believe that this proposal may be a good starting point for discussion in the DG workshop.

ACA/DEAA further recommended that the Texas standard is best suited for application to the APS system and that the provisions of California rule 21 would serve as a second choice for DG standards in Arizona. ACA/DEAA also recommended that the Commission consider a program to install self generation to reduce the electricity on the power grid. We believe that both of these recommendations should also be discussed and developed during the course of the workshop.

The proponents of the Settlement Agreement recommend that specific issues concerning DG should be addressed in workshops devoted to distributed generation. Paragraphs 108 and 109 direct Staff to schedule workshops to address outstanding DG issues. They believe that such a process would use the work done in previous workshops and would also address the technical aspects of connecting distributed generation in a way that would apply to all regulated utilities in Arizona. To be successful, the process would require a strict timetable for producing recommendations for the Commission's consideration. The proponents argue that Schedule E-32 should not be redesigned to meet the specialized needs of partial requirements service, but that the rate design for partial requirements service should be addressed in the workshop. Approximately 95,000 full requirement customers receive service under Schedule E-32, and according to the proponents, it is an integral part of the Settlement Agreement. The proponents believe that ACA/DEAA's proposal to put the rate increase in the energy portion would create a massive subsidy from higher load factor customers to lower load factor customers. The demand related charges are necessary for pricing the capacity related costs of the APS system for the full requirement customers. The proponents argue that DG requires partial requirement service – which is a very specialized product that includes maintenance power, standby power, and supplemental power – and it should have its own rate, which can be addressed in the proposed DG workshop.

We agree with ACA/DEAA that DG can have significant benefits to APS and to its ratepayers and we want to encourage the growth of DG that can provide those benefits. Additionally, we find some of the suggestions made in ACA/DEAA's post hearing brief persuasive. However, our decision is rooted in the record made in this case, and those suggestions were not fully delineated, nor subjected to cross examination at the Hearing. At this point, we agree with the participants that the E-32 schedule should not be modified to accommodate the particular needs associated with DG. Therefore, we believe that the parties should address the issue of an appropriate rate schedule for DG during the workshop process, and direct the parties to develop a schedule that is designed particularly for DG customers. Further, we direct the parties to begin the process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

s. **Bark Beetle Remediation**

APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control. In the next rate case, the Commission will determine the reasonableness, prudence, and allocation of the costs, and will determine the appropriate amortization period.

t. **Rate Design**

Attached to the Settlement Agreement is Appendix J, which sets forth the rates adopted in the Settlement Agreement. The rates are designed to permit APS to recover an additional $67.5 million in base revenues, including an additional 3.94 percent for the residential rate class and a 3.57 percent increase for the general service rate class. The rates were designed to move toward costs and remove subsidizations, thereby promoting equity among customers. The base rates will also permit cost-based unbundling of distribution and revenue cycle services, including metering, and meter reading and billing. The parties believe that this will give appropriate price signals necessary for shopping. APS will continue on-peak and off-peak rates for winter billing for all residential time-of-use customers under Schedules ET-1 and ECT-1R. Within 180 days APS will submit a study to Staff that examines other ways APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, making those periods more reflective of actual system peak time periods. APS shall also include in the aforementioned study a cost-benefit analysis of Surepay, APS' automatic payment program. The Company is to examine the cost effectiveness of the program and to explore the possibility of offering a discount to those customer who participate in Surepay. The Settlement Agreement adopts APS' proposed experimental time-of-use periods for ET-1 and ECT-1R. For general service customers, the existing on-peak time periods will remain the same and the summer rate period will begin in May and conclude in October. The general service rate schedules will also permit cost-based unbundling of generation and revenue cycle services and will be differentiated by voltage levels. An additional primary service discount of $2.74/kW for military base customers served directly from APS substations will be adopted. The Settlement Agreement modifies Schedule E-32 in order to simplify the design, make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. A time-of-use option will also be available to E-32 customers. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-32-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand[37] and that the initial rate block for residual off-peak delivery should be applied only to the first 100kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings. As discussed above, ACA/DEAA objected to the company's E-32 schedule. One of ACA/DEAA's concern was the almost doubling of the demand charge. The Commission has open dockets involving APS' metering and bill estimation procedures, including the estimation of demand. Although we are not resolving those issues in this rate case, we are concerned that APS properly meter, read meters and bill its customers timely and accurately.[38] It is imperative, especially given

[37] Instead of remaining at the initial level of $7.722 per kW-month, after the first 100 kW of demand, the unbundled residual off-peak demand charge for delivery at Secondary voltage will be reduced to $3.497; after the first 100kW of demand, the unbundled residual off-peak demand charge for delivery at Primary voltage will be reduced to $2.877, with both of these changes incorporated into the bundled rate as well.

[38] Also, we note that apparently APS is deleting a bill estimation procedure for EC-1 and ECT-1R. It is not clear whether these are the tariffs that Staff has alleged APS has not been following, but nothing in this Decision will affect our ability to make findings in Docket Nos. E-01345A-04-0657, et al. or impose any appropriate fines, sanctions, or remedies in those dockets.

the increase in the demand charge, that APS reduce the instances where it estimates demand.

In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

Several schedules are "frozen" and APS will provide notice approved by Staff to those customers that those rates will be eliminated in APS' next rate case. Such notice will be provided at the conclusion of this docket and at the time that APS files its next rate case.

u. <u>Litigation and other issues</u>

The Settlement Agreement provides that APS will dismiss with prejudice all appeals of Decision No. 65154, the Track A Order, and APS and its affiliates will dismiss litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract, and APS and its affiliates shall forgo any claim that APS, PWEC, Pinnacle West Capital Corporation or any of APS' affiliates were harmed by Decision No. 65154, and the Preliminary Inquiry ordered in Decision No. 65796 shall be concluded with no further action by the Commission, once the Settlement Agreement is approved in accordance with Section XXI of the Settlement Agreement by a Commission Decision that is final and no longer subject to judicial review.

The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

V. Summary

This Settlement Agreement resolves numerous significant, complex, and conflicting issues affecting many parties with very different perspectives and interests. As with every settlement, the give and take nature of negotiations ends up with a product that no one party initially proposed. The key question when deciding whether to approve such a settlement is whether the end result resolves the important issues fairly and reasonably when taken together as a whole, and in such a way that will promote the public interest. We believe that the Settlement Agreement reached by these 22 parties, with the modifications that we make herein, reaches such a result. Our agreement to rate base the PWEC assets does not mean that we are retreating from our commitment to encourage the development of competition, and we expect APS and its affiliates to fully comply with all the pro-competition requirements in the Settlement Agreement and other Commission decisions and rules. Additionally, our adoption of a PSA will be a significant change for APS customers, and we expect APS to educate and inform its customers about all aspects of that adjustor charge in a way that will minimize confusion and misunderstandings. We also expect APS to have the required information posted to its website and its customer education program up and running before June 1, 2005, in order to allow customers the opportunity to implement their own conservation measures. Finally, we want to make it clear to APS that our adoption of a PSA does not relieve it of its obligation to effectively and efficiently manage its fuel costs, and that we will closely monitor APS' performance.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

IV. FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On June 27, 2003, APS filed with the Commission an application for a $175.1 million rate increase and for approval of a purchased power contract.

3. Notice of the application was provided in accordance with the law.

4. Intervention was granted to AECC, FEA, Kroger, RUCO, AUIA, Phelps Dodge, IBEW, ACA/DEAA, Panda, AWC, SWG, WRA, CNE, SEL, DVEP, UES, ACAA, Alliance, Wickenburg, AriSEIA, AARP, SWEEP, PPL Sundance, PPL Southwest, SWPG, Mesquite, and Bowie.

5. By Procedural Order issued August 15, 2003, the hearing was set to commence on April 7, 2004, and procedural dates were established for the filing of testimony and evidence.

6. On February 6, 2004, APS filed a Motion to Amend the Rate Case Procedural Schedule, and a procedural conference was held on February 18, 2004 to discuss the Motion.

7. By Amended Rate Case Procedural Order issued on February 20, 2004, the hearing date was rescheduled for May 25, 2004 and other procedural dates were modified.

8. On April 6, 2004, Staff filed a Motion to Amend the Procedural Schedule and on April 8, 2004, Staff filed a Memorandum indicating that representatives of APS had contacted Staff about the possibility of conducting settlement negotiations.

9. A public comment hearing was held on April 7, 2004.

10. On April 13, 2004, APS filed its Response to Staff's Motion and Staff Notice of Settlement Negotiations and requested a temporary suspension of the procedural schedule in order for settlement discussions to take place.

11. Pursuant to Procedural Orders issued April 7 and 12, 2004, a procedural conference to discuss Staff's Motion was held on April 15, 2004. By Procedural Order issued April 16, 2004, new

procedural dates were established and another procedural conference was scheduled for April 28, 2004.

12. The April 28, 2004 procedural conference was held as scheduled and by Procedural Order issued April 29, 2004, the procedural schedule was stayed and another procedural conference was scheduled for May 26, 2004.

13. Pursuant to procedural conferences held on May 26 and June 14, 2004, and Procedural Orders issued on May 26, June 18, and July 20, 2004, the stay was extended in order to allow the parties to discuss settlement.

14. At the August 18, 2004 Procedural Conference, the parties announced that they had reached a settlement, and the Settlement Agreement was docketed on that date.

15. On August 20, 2004, an Amended Rate Case Procedural Order was issued setting the hearing on the Settlement Agreement to commence on November 8, 2004.

16. The hearing was held as scheduled on November 8, 9, 10, 29, 30 and December 1, 2, and 3, 2004. Public comment was taken and testimony from the proponents of the Settlement Agreement was presented in panel format, and testimony from the ACA/DEAA was also presented in a panel format.

17. The Test Year ending 2002 Plant in Service was $4,876,901,000, excluding transmission plant, and including the PWEC assets as of December 31, 2004.

18. APS' FVRB is $5,054,426,000 and a 5.92 fair value rate of return is appropriate.

19. It is just and reasonable to authorize a total annual revenue increase in the amount of $75,500,000, consisting of an increase in base rates of approximately 3.77 percent or $67.6 million, and an increase in the CRCC surcharge of approximately .44 percent, which will collect $7.9 million.

20. A Power Supply Adjustor as set forth in the Settlement Agreement and as modified herein, is in the public interest.

21. APS is authorized to acquire the PWEC generation assets and rate base those assets at a value of $700 million as of December 31, 2004, under the terms and conditions as set forth in the Settlement Agreement and herein.

22. The Settlement Agreement will allow APS the opportunity to earn a reasonable rate of

return on its investment, will provide revenues sufficient for the Company to provide efficient and reliable service, and will allow for continued development of electric competition in Arizona.

23. APS shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. APS shall submit its plan to implement its customer education program within 30 days of the effective date of this Decision to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program. Furthermore, APS shall post the required information on its website within 30 days of the effective date of this Decision.

24. The parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

25. The depreciation rates and the costs for nuclear decommissioning as set forth in the Settlement Agreement are reasonable and appropriate.

26. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-032-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand and that the initial rate block for residual off-peak delivery should be applied only to the first 100 kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings.

27. We direct the parties to begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

28. In its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, APS shall also include a cost-benefit analysis of Surepay, APS' automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

29. APS shall file additional time-of-use programs that are similar to the Time Advantage

and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

30. In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

31. In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

32. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

33. We are modifying the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator, and we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation issued

before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to any generating facility or interest in a generating facility ultimately acquired by APS.

34. The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

35. The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

36. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005.

37. If Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

38. We agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can

determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

39. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

40. Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

41. APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance program. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

42. The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

V. CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-222, 250, 251, and 376.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. The Settlement Agreement, with the modifications and additional provisions contained herein, resolves all matters raised by APS' rate application in a manner that is just and reasonable, and promotes the public interest.

5. The fair value of APS' rate base is $5,054,426,000, and 5.92 percent is a reasonable rate of return on APS' rate base.

6. The rates, charges, and conditions of service established herein are just and reasonable.

7. APS should be directed to file revised tariffs consistent with the Settlement Agreement and the findings contained in this Order.

VI. ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement attached hereto as Attachment A as modified herein is approved.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before March 31, 2005, revised schedules of rates and charges consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after April 1, 2005.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form approved by the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall submit its plan to implement its customer education program to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall post on its website, information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement including filing all reports, studies, and plans as set forth in the Settlement Agreement and as modified herein.

IT IS FURTHER ORDERED that the parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall forgo any present or future claims of stranded costs associated with any of the PWEC assets.

IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall schedule workshops on resource planning issues and distributed generation issues within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall modify Rate E-32-TOU in accordance with the discussion and findings herein.

IT IS FURTHER ORDERED that the parties shall begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

IT IS FURTHER ORDERED that in its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, Arizona Public Service Company shall also include a cost-benefit analysis of Surepay, Arizona Public Service Company's automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company's rate design study shall include the issues addressed in Findings of Fact No. 30, and Arizona Public Service Company shall propose a rate design addressing these issues in its next rate case.

IT IS FURTHER ORDERED that in order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

IT IS FURTHER ORDERED that all DSM year-end reports filed at the Commission by Arizona Public Service Company must be certified by an Officer of the Company.

IT IS FURTHER ORDERED that Arizona Public Service Company shall comply with Findings of Facts No. 33 when acquiring a generating unit or an interest in one.

IT IS FURTHER ORDERED that the resource planning workshops shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations.

IT IS FURTHER ORDERED that in order to take advantage of any available federal tax credits for renewable energy production, Arizona Public Service Company shall issue the 100 MW RFP no later than May 15, 2005.

IT IS FURTHER ORDERED that if Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

IT IS FURTHER ORDERED that within three years of the effective date of this Decision, Staff shall commence a procurement review of Arizona Public Service Company's fuel, purchased power, generating practices and off-system sales practices.

IT IS FURTHER ORDERED that the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan shall be filed with the Commission and made available to Tribal authorities within Arizona Public Service Company's service territory.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas, and Arizona Public Service Company shall participate in any future dockets related to enhancing reliability statewide.

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IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall initiate a rulemaking proceeding to modify A.A.C. R14-2-1618 within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN	COMMISSIONER	COMMISSIONER
COMMISSIONER	COMMISSIONER	

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 7th day of April, 2005.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT Lowell S Gleason

DISSENT ____________________

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DOCKET NO.: E-01345A-03-0437

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ATTACHMENT A

PROPOSED SETTLEMENT

OF

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

REQUEST FOR RATE ADJUSTMENT

PROPOSED SETTLEMENT
OF
DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY
REQUEST FOR RATE ADJUSTMENT

The purpose of this agreement ("Agreement") is to settle disputed issues related to Docket No. E-01345A-03-0437, Arizona Public Service Company's application to increase rates. This Agreement is entered into by the following entities:

Arizona Public Service Company ("APS")
Arizona Competitive Power Alliance
Federal Executive Agencies
Constellation NewEnergy, Inc.
Strategic Energy, L.L.C.
Southwest Energy Efficiency Project
Western Resource Advocates
Mesquite Power, L.L.C.
PPL Sundance Energy, L.L.C.
PPL Southwest Generation Holdings, L.L.C.
Arizonans for Electric Choice and Competition
Phelps Dodge Mining Company
Arizona Utility Investors Association
Southwestern Power Group II, LLC
Bowie Power Station
Arizona Community Action Association
IBEW, AFL-CIO, CLC, Local Unions 387, 640, and 769
Kroger Co.
Dome Valley Energy Partners, L.L.C.
Arizona Solar Energy Industries Association
Residential Utility Consumer Office
Staff, Arizona Corporation Commission

These entities shall be referred to collectively as "Parties." The following numbered paragraphs comprise the Parties' Agreement.

RECITALS

1. The purpose of this Agreement is to settle all issues presented by Docket No. E-01345A-03-0437 in a manner that will promote the public interest.

2. The Parties agree that the negotiation process undertaken in this matter was open to all Intervenors and provided all Intervenors with an equal opportunity to participate. All Intervenors were notified of the settlement process and encouraged to participate.

3. The Parties agree that the terms of this Agreement will serve the public interest by providing a just and reasonable resolution of the issues presented by APS' rate case, Docket No. E-01345A-03-0437. The adoption of this Agreement will further serve the public interest by allowing the Parties to avoid the expense and delay associated with litigation.

TABLE OF CONENTS

TERMS AND CONDITIONS

I. Revenue Requirement

4. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS will receive a total increase of $75,500,000 over its adjusted 2002 test year revenue of $1,791,584,000. This amount is equal to an approximate 3.77 percent increase in base rates plus an approximate .44 percent increase for the Competition Rules Compliance Charge discussed in Section XI of this Agreement. This equals a total increase of approximately 4.21 percent over APS' adjusted test year revenue.

5. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS shall have a fair value rate base of $6,281,885,000. The revenue increase established in this Agreement will provide APS with an opportunity to earn a fair value rate of return of 5.92 percent.

II. PWEC Asset Treatment

6. In consideration of the provisions of this Agreement as a whole, the Parties agree that it is in the public interest for APS to acquire and to rate base the following units currently owned by Pinnacle West Energy Corporation ("PWEC"): West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 (collectively, the "PWEC Assets"). The generation costs related to these units will be recovered in the generation component of unbundled rates; the ancillary service costs related to these units will be recovered in the transmission component of unbundled rates.

7. The PWEC Assets shall have an original cost rate base value of $700 million, which represents a $148,000,000 disallowance from the original cost of these assets as of December 31, 2004. This disallowance represents a reasonable estimate of the value to APS' ratepayers of the remaining term of the Track B contract between APS and PWEC.

8. APS will forego any present or future claims of stranded costs associated with any of the PWEC Assets.

9. The Parties recognize that APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS will use its best efforts to obtain such approval. APS shall file a request for FERC approval of the asset transfer no sooner than the date of the Commission's approval of this matter but no later than thirty days after such approval. If the Commission approves the Agreement without material change, APS shall be authorized to inform FERC that the Parties support APS' efforts to obtain FERC approval of the specific asset transfer set forth in this Agreement. If the Commission approves the Agreement with one or more material changes, APS shall not claim the support of any Party that is adversely affected by the material change(s) without first obtaining that Party's consent. No Party shall file with FERC any objection to the asset transfer, and no Party shall be

obligated to intervene or to join or file any pleadings in support of FERC approval of the asset transfer.

10. To bridge the time between the effective date of the rate increase and the actual date of the asset transfer, APS and PWEC will execute a cost-based purchased power agreement ("Bridge PPA"), which will be based on the value of the PWEC Assets established in Paragraph 7. During the term of the Bridge PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the power supply adjustor ("PSA") addressed in Section IV below. Any demand and non-fuel energy charges incurred under this Bridge PPA will be excluded from recovery under the PSA because they are already included in APS' base rates.

11. The Bridge PPA shall remain in effect until FERC issues a final order approving the transfer of the PWEC assets to APS and such transfer is completed. For purposes of this paragraph, a "final order" is an order that is no longer subject to appeal.

12. If FERC issues an order denying APS' request to acquire the PWEC Assets, the Bridge PPA will become a thirty-year PPA. Prices in this thirty-year PPA will reflect cost-of-service as determined by the Commission in APS' rate proceedings as if APS had acquired and rate-based the PWEC Assets at the value established in Paragraph 7. During the term of the thirty-year PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the PSA addressed in Section IV below. Unless otherwise ordered by the Commission, any demand and non-fuel energy charges incurred under this long-term PPA will be excluded from recovery under the PSA and will instead be reflected in APS' base rates. Except as specifically set forth in this Paragraph, this Agreement does not establish the regulatory or ratemaking treatment of the long-term PPA.

13. If FERC issues an order approving APS' request to acquire the PWEC Assets at a value materially less than $700 million, or if FERC issues an order approving the transfer of fewer than all of the PWEC Assets, or if FERC issues an order that is materially inconsistent with this Agreement, APS shall promptly file an appropriate application with the Commission so that rates may be adjusted. In these circumstances, the Bridge PPA shall continue at least until the conclusion of this subsequent proceeding to consider any appropriate adjustment to APS' rates.

14. The basis point credit established in Decision No. 65796 will continue as long as the associated debt between APS and PWEC is outstanding. Credit for amounts deferred after December 31, 2004 shall be reflected in APS' next general rate proceeding.

15. The Parties agree that West Phoenix CC-4 and West Phoenix CC-5 shall be deemed to be "local generation" as that term is defined in the AISA protocol or any successor FERC-approved protocol. During must-run conditions, generation from the West Phoenix facility shall be available at FERC-approved cost-of-service prices to electric service providers serving direct access load in the Phoenix load pocket.

III. Cost of Capital

16. The Parties agree that a capital structure of 55% long-term debt and 45% common equity shall be adopted for ratemaking purposes.

17. The Parties agree that a return on common equity of 10.25% is appropriate.

18. The Parties agree that an embedded cost of long-term debt of 5.8% is appropriate.

IV. Power Supply Adjustor

19. A Power Supply Adjustor ("PSA") shall be adopted with the following characteristics.

a. The PSA shall include both fuel and purchased power.

b. The adjustor rate, initially set at zero, will be reset on April 1, 2006 and thereafter on April 1st of each subsequent year. APS will submit a publicly available report that shows the calculation of the new rate on March 1, 2006 and thereafter on March 1st of each subsequent year. The adjustor rate shall become effective with the first billing cycle in April unless suspended by the Commission.

c. There shall be an incentive mechanism where APS and its customers shall share in the costs or savings. The percentage of sharing shall be ninety (90) percent for the customers and ten (10) percent for APS with no maximum sharing amount.

d. There shall be a bandwidth which shall limit the change in the adjustor rate to plus or minus $0.004 per kilowatt hour ("kWh") per year. Any additional recoverable or refundable amounts shall be recorded in a balancing account and shall carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing as described above in Paragraph 19.c in the subsequent year or years.

e. When the size of the balancing account reaches either plus or minus $50 million, APS will have forty-five days to file for Commission approval of a surcharge to amortize the over-recovered/under-recovered balance and to reset the balancing account to zero. If APS does not want to reset the balance to zero, it shall file a report explaining why. Commission action shall be required to establish or revise a surcharge created pursuant to this provision.

f. Subject to paragraphs 19.c and 19.d, ratepayers shall receive the benefits of all off-system sales margins through a credit to the PSA balance.

g. The PSA is the appropriate mechanism for recovery of the prudent direct costs of contracts used for hedging fuel and purchased power costs.

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h. The balancing account shall accrue interest based on the one-year nominal Treasury constant maturities rate. This rate is contained in the Federal Reserve Statistical Release, H-15, or its successor publication.

i. The Commission or its Staff may review the prudence of fuel and power purchases at any time.

j. The Commission or its Staff may review any calculations associated with the PSA at any time.

k. Any costs flowed through the adjustor shall be subject to refund if the Commission later determines that the costs were not prudently incurred.

20. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. These monthly reports shall thereafter be due on the first day of the third month following the end of the reporting month. These reports shall be publicly available and shall contain, at a minimum, the following items:

a. Bank balance calculation, including all inputs and outputs.

b. Total power and fuel costs.

c Customer sales in both kWh and dollars by customer class.

d. The number of customers by customer class.

e. A detailed listing of all items excluded from the PSA calculations.

f. A detailed listing of any adjustments to adjustor reports.

g. Total off-system sales margins.

h. System losses in MW and MWh.

i. Monthly maximum retail demand in MW.

j. Identification of a contact person and phone number from APS for questions.

21. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide additional reports to Staff each month including information as set forth in paragraphs 22, 23, and 24 about APS' generating units, power purchases, and fuel purchases. These monthly reports shall thereafter be due on the first day of the third month

following the end of the reporting month. These additional reports may be provided confidentially.

22. The information for each generating unit shall include, at a minimum, the following items:

a. The net generation, in MWh per month, and twelve months cumulatively.

b. The average heat rate, both monthly and twelve-month average.

c. The equivalent forced-outage rate, both monthly and twelve-month average.

d. The outage information for each month, including, but not limited to event type, start date and time, end date and time, description.

e. Total fuel costs per month.

f. The fuel cost per kWh per month.

23. At a minimum, the information on power purchases shall consist of the following items per seller:

a. The quantity purchased in MWh.

b. The demand purchased in MW to the extent specified in contract.

c. The total cost for demand to the extent specified in contract.

d. The total cost for energy.

Information on economy interchange purchases may be aggregated. These reports shall also include an itemization of off-system sales margins.

24. At a minimum, the information on fuel purchases shall consist of the following information:

a. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge and incremental cost.

b. Natural gas commodity costs, categorized by short term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume, by contract.

25. Within sixty days after Commission approval of this Agreement, APS shall provide the information specified in paragraphs 20-24 relating to the base cost of fuel and purchased power adopted for the test year settlement revenue requirement.

26. An APS Officer shall certify under oath that all information provided in the reports required under Paragraphs 20 through 25 is true and accurate to the best of his or her information and belief.

27. Direct access customers and customers served under Rates E-36, SP-1, Solar-1, and Solar-2 shall be excluded from paying charges under the PSA.

28. The minimum life of the PSA shall be five years measured from the date that rates resulting from this proceeding go into effect. No later than four years from the date of the PSA's implementation, APS shall file a report that addresses the PSA's operation, its merits, and its shortcomings and that provides recommendations, with supporting testimony, as to whether the PSA should remain in effect. The Commission shall consider whether to continue the PSA after APS has filed its PSA report or during APS' next rate case, whichever comes first. If the PSA is reviewed during an APS rate case that concludes before the expiration of the five-year period, or if the Commission's review of APS' PSA report concludes before the expiration of the five-year period, any recommendations to abolish the PSA shall not take effect until the five-year period has expired.

29. If the Commission decides to retain the PSA after the review described in paragraph 28, the Commission may nonetheless, in conformance with applicable procedural requirements, abolish the PSA at any time after the five-year period has expired and need not conduct a rate case to do so.

30. If the Commission abolishes the PSA, the Commission shall make appropriate provision for any under-recovery or over-recovery that exists at the time of termination. The Commission may also adjust APS' base rates as appropriate to ensure that they reflect the costs for fuel and purchased power.

31. The Parties agree to a base cost of fuel and purchased power of $0.020743 per kWh. This amount shall be reflected in APS' base rates.

32. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the PSA shall operate.

V. Depreciation

33. APS has agreed to adopt Staff's proposed service lives as set forth in Staff's direct testimony, including the service lives proposed by Staff for the PWEC Assets. The Parties further agree that APS shall be allowed a jurisdictional net salvage allowance as reflected in APS' direct testimony.

34. The attached Appendix A sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property agreed to by the Parties for purposes of this proceeding and authorized by the Commission's approval of this Agreement.

35. APS will separately record and account for net salvage such that it can be identified both as a component to annual depreciation expense and in accumulated reserves for depreciation.

36. Amortization rates currently in effect, which are shown in Appendix A, are to remain in effect.

37. For the purposes of this proceeding, the Parties agree that SFAS 143 shall not be adopted for ratemaking purposes.

VI. $234 Million Write-Off

38. APS shall not recover the $234 million write-off attributable to Decision No. 61973, the Commission order that approved the 1999 APS Settlement Agreement.

39. APS shall not seek to recover the above $234 million write-off in any subsequent proceeding.

VII. Demand Side Management ("DSM")

40. Included in APS' total test year settlement base rate revenue requirement is an annual $10 million base rate DSM allowance for the costs of approved "eligible DSM-related items," as defined in this paragraph. In addition to expending the annual $10 million base rate allowance, APS will be obligated to spend on average at least another $6 million annually on approved eligible DSM-related items, such additional amounts to be recovered by means of a DSM adjustment mechanism as described in paragraph 43 herein. Accordingly, APS will be obligated under this Settlement Agreement to spend at least $48 million ($30 million in base rates and at least another $18 million during calendar years 2005 – 2007, with the latter amount to be recovered by the aforementioned DSM adjustment mechanism) on approved eligible DSM-related items, all as provided in this Section VII. For purposes of this Agreement, "eligible DSM-related items" shall include and be limited to "energy-efficiency DSM programs", as also defined in this paragraph; a "performance incentive" in accordance with paragraph 45; and "low income bill assistance" as specified in paragraph 42. For purposes of this Agreement, "energy-efficiency DSM" shall be defined as the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices.

41. All DSM programs must be pre-approved before APS may include their costs in any determination of total DSM costs incurred. APS may apply the costs of programs already approved by Staff or the Commission prior to the effective date of Commission approval of this Agreement to the annual $10 million base rate DSM allowance and to the additional spending on eligible DSM-related items provided for in paragraphs 40 and 44. After the Commission issues an order approving the terms of this Agreement, APS shall submit proposed DSM programs to the Commission for approval.

42. The annual $10 million base rate DSM allowance referenced above shall include at least $1 million annually for the low income weatherization program. Up to $250,000 of the $1 million provided for the low income weatherization program may be applied to low income bill assistance during any calendar year. If APS does not expend the entire $250,000 on low income bill assistance, the balance shall be available for low income weatherization. APS shall file an application for Commission approval of the low income weatherization program, including bill assistance and administrative costs, within sixty days of the Commission's approval of this Agreement.

43. A DSM adjustment mechanism will be established in this proceeding for any approved DSM expenditures in excess of the annual $10 million base rate DSM allowance. The adjustor rate, initially set at zero, will be reset on March 1, 2006 and thereafter on March 1st of each subsequent year. Before March 1st, beginning in 2006, APS shall file a request with supporting documentation to revise its DSM adjustor rate. The per-kWh charge for the year will be calculated by dividing the account balance by the number of kWh used by customers in the previous calendar year. General Service customers that are demand billed will pay a per kW charge instead of a per kWh charge. To calculate the per kW charge, the account balance shall first be allocated to the General Service class based upon the number of kWh consumed by that class. General Service customers that are not demand billed shall pay the DSM adjustor rate on a per kWh basis. The remainder of the account balance allocated to the General Service class shall then be divided by the kW billing determinant for the demand billed customers in that class to determine the per kW DSM adjustor charge. The DSM adjustor will be applied to both standard offer and direct access customers.

44. As provided for in paragraph 40, and in addition to the annual $10 million base rate DSM allowance, APS will spend on average at least $6 million annually on approved eligible DSM-related items to be recovered by the DSM adjustor mechanism established in paragraph 43. APS may gradually phase-in its DSM spending, but will be obligated to expend no less than $48 million, $30 million in base rates and at least $18 million to be recovered through the DSM adjustment mechanism established under paragraph 43, all on approved and eligible DSM-related items over the initial three-year period of calendar years 2005 through 2007. Moreover, APS will be obligated to expend at least $13 million on approved and eligible DSM-related items during 2005 (subject to the Commission's timely approval of sufficient programs), with such $13 million spending obligation to be pro-rated for 2005 to the extent Commission approval of the Final Plan called for in paragraph 48 occurs after January 1, 2005. In no event will such pro-ration reduce APS' 2005 obligation below the annual $10 million base rate DSM allowance. Consistent with paragraph 43, all required and approved spending on eligible DSM-related items above the annual $10 million base rate allowance will be recovered by APS only on an "after-the-fact" basis through the DSM adjustment mechanism.

45. APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with paragraph 41. Such performance incentive will be capped at 10% of the total amount of DSM spending, inclusive of the program incentive, provided for in this Agreement (e.g., $1.6 million out of the $16 million average annual spending referenced in paragraphs 40 and 44 or $4.8 million over the initial three-year period). Any such performance

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incentive collected by APS during a test year will be considered as a credit against APS' test year base revenue requirement. The specific performance incentive will be set forth in and approved as a part of the Final Plan referenced in paragraph 48.

46. This Agreement does not provide for the recovery of net lost revenues. Except to the extent reflected in a test year used to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding, APS shall not recover or seek to recover net lost revenues on a going-forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such test year or for periods prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding. In addition, no recovery of net lost revenues by APS will reduce the DSM spending commitments embodied in this Agreement or be considered as an eligible DSM-related item for purposes of this Section.

47. Attached as Appendix B is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for calendar 2005, including a listing and brief description of programs, program concepts and program strategies and tactics. The Preliminary Plan also provides a preliminary allocation of the $16 million referenced in paragraph 40. The Preliminary Plan will be considered and approved by the Commission as part of this Agreement.

48. Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative created pursuant to paragraph 54, file with the Commission a final 2005 DSM plan ("Final Plan") that is consistent with the approved Preliminary Plan. The Final Plan will be submitted to the Commission for its consideration and approval. As part of the Commission's review, Staff shall report its recommendation to the Commission regarding the Final Plan, including its recommendations regarding the program budgets, estimates of energy savings and load reductions, and the cost-effectiveness of such Final Plan.

49. APS may request Commission approval for DSM program costs and performance incentives that exceed the $16 million ($48 million over three years) level referenced in paragraph 40. Such additional DSM programs may include demand-side response and additional energy efficiency programs.

50. For residential billing purposes, APS shall combine the DSM adjustor with the EPS adjustor addressed in paragraph 63 and shall reflect such combined billing charge as an "Environmental Benefits Surcharge." For the billing of general service and other non-residential customers, APS may but is not required to provide for such combined billing of the EPS and DSM adjustment mechanisms. In any event, each such adjustor shall be separately set forth in the Company's rate schedules and shall be separately accounted for in the Company's books, records, and reports to the Commission.

51. If, notwithstanding the provisions of paragraphs 40 and 44, APS does not expend during calendar years 2005 through 2007 at least $30 million (in total) of the base rate allowance referenced in paragraph 40 for approved and eligible DSM-related items, as that latter term is defined in paragraph 40, the unspent amount of the $30 million will be credited to the account balance for the DSM adjustor described in Paragraph 43 in 2008.

52. Beginning in 2005, APS will file mid-year and end-year reports in Docket Control containing the following information separately for each DSM program:

a. A brief description of the program.

b. Program modifications.

c. Program goals, objectives, and savings targets.

d. Programs terminated.

e. The level of participation.

f. A description of evaluation and monitoring activities and results.

g. kW and kWh savings.

h. Benefits and net benefits, both in dollars, as well as performance incentive calculation.

i. Problems encountered and proposed solutions.

j. Costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs.

k. Findings from all research projects.

l. Other significant information.

Each report will be due on the first day of the third month after the conclusion of the reporting period.

53. Direct access customers shall be eligible to participate in APS DSM programs.

54. APS shall implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance. The DSM working group shall review APS' draft program plans and reports before APS submits them to the Commission. APS shall, however, retain responsibility for demonstrating to the Commission the appropriateness of any program proposed by APS. Any DSM program proposed by APS may be modified by the Commission as it finds appropriate. If APS does not submit a DSM program proposal considered by the collaborative DSM working group to the Commission, any member of the working group may submit the proposal directly to the Commission for its review and approval with such modifications as the Commission finds appropriate. In such instance, the member or members submitting a proposal shall have the responsibility for demonstrating the appropriateness of that

program to the Commission. At a minimum, Staff, RUCO, AECC, the Arizona State Energy Office, WRA and SWEEP will be invited to participate with APS in the above collaborative DSM working group. Commission Staff shall continue to exercise its responsibility to review and make independent recommendations to the Commission in connection with any DSM program proposal submitted by APS or any other member of the working group.

55. APS shall conduct a study to review and evaluate the merits of allowing large customers to self-direct any DSM investments. In conducting this study, APS shall seek the input of the collaborative DSM working group provided by paragraph 54. This study shall be filed within one year of the Commission's approval of this Agreement.

56. Any customer who can demonstrate an active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

57. Rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand are integral parts of an overall DSM strategy. To that end, APS will conduct a study analyzing rate design modifications that could include, among others, consideration of mandatory TOU rates (e.g., for E-32 general service customers) and/or expanded use of inclining block rates. A plan for such study and analysis of rate design modifications shall be presented to the collaborative DSM working group described in paragraph 54 within 90 days of the Commission's approval of this Agreement. APS will submit to the Commission the final results of this study and analysis of rate design modifications as part of its next general rate application or within 15 months of approval of this Agreement, whichever occurs first. If the study and analysis indicate that one or more of the rate design modifications studied is reasonable, cost-effective and practical, APS shall develop and propose to the Commission any appropriate rate design modifications.

58. The DSM activities provided for in this section are in addition to any DSM acquired as part of the competitive procurement process described in Section IX.

59. The Commission will address other issues, such as DSM goals, cost-effectiveness, and evaluation, in a generic proceeding.

60. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the DSM adjustor shall operate. Commission Staff shall review and approve the plan of administration in connection with its overall compliance review following APS' compliance filings in this docket.

VIII. Environmental Portfolio Standard and other Renewables Programs

61. Included in APS' total test year settlement revenue requirement and existing EPS surcharge revenues is $12.5 million for renewables as defined in the Commission's environmental portfolio standard ("EPS"), A.A.C. R14-2-1618 ("Rule 1618").

62. APS shall recover $6 million of the above $12.5 million in the base rates provided for in this Agreement.

63. APS shall also recover costs for EPS-eligible renewables through the EPS surcharge, which shall be established in this case as an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding. The initial charge will be the same as contained in the current EPS surcharge tariff, including caps. If the Commission amends the EPS surcharge set forth in Rule 1618 or approves additional EPS funding pursuant to paragraph 64 of this Agreement, any change in EPS funding requirements resulting from such actions shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. These adjustments may be made outside a rate case.

64. Prior to spending additional funds, APS may apply to the Commission to increase its EPS funding beyond that provided in base rates and the EPS surcharge. In its application, APS shall provide the following information:

a. APS shall explain why it has been unable to meet the standard.

b. APS shall account for all EPS funds that it has collected from ratepayers and shall describe how they were spent.

c. APS shall support the prudence and cost effectiveness of all its EPS expenditures.

d. APS shall demonstrate that it has appropriately managed its EPS funding and programs.

e. If APS has chosen to expend EPS funding on technologies, programs, or other items that do not represent the least cost method for meeting the standard established in Rule 1618, APS shall identify each such instance and explain why it chose to employ other than the least cost alternative.

f. APS shall set forth a plan for meeting the standard and shall support the cost effectiveness of each element of the plan. Where the plan does not employ the least cost alternative, APS shall identify each such instance and shall explain why it is reasonable to elect a more expensive alternative.

g. APS shall provide the proposed budget that it believes would allow it to meet the standard and shall explain the cost effectiveness of every item addressed in the budget.

h. In its application, APS shall address whether ratepayers would benefit from partial or phased implementation of the plan and associated budget provided in response to paragraphs 64.f and 64.g.

i. APS shall identify any potential impacts on ratepayers of additional EPS funding and shall consider how any adverse impacts may be mitigated.

The Commission, in its discretion, may deny APS' application for additional EPS funding. APS may not file an application pursuant to this paragraph until one year after the termination of the rulemaking docket resulting from paragraph 68.

65. The EPS surcharge shall be recovered from both standard offer and direct access customers. APS shall separately account for EPS revenue collected from direct access customers, and such revenue shall be available to electric service providers for funding their EPS obligations.

66. For billing purposes, APS may combine the EPS adjustor with the DSM adjustor as addressed in paragraph 50.

67. After the Commission issues an order approving the terms of this Agreement, renewables programs directly involving APS' retail customers will be submitted to the Commission for approval.

68. The Commission will address issues such as modifying EPS goals or requirements in a generic proceeding. Staff will initiate a rulemaking proceeding to modify Rule 1618 within 120 days of the Commission's approval of this Agreement.

69. APS will issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of any of the following types of renewable energy resources for delivery beginning in 2006: solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas), or geothermal. APS will, either in this solicitation or in subsequent procurements for renewables, seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. The renewable resources solicited by this RFP or future solicitations issued pursuant to this paragraph shall be subject to the following conditions:

a. Resources need not provide firm capacity, but APS will take into consideration the degree of the resource's firmness in determining the appropriate capacity value to assign to such resource.

b. Individual resources must be capable of providing at least 20,000 MWh of renewable energy annually.

c. Resources must be deliverable to the APS system, either directly or through displacement (tradable tags or credits alone will not suffice), and the costs of integrating a specified resource into the APS system will be considered in determining whether a proposed resource meets the pricing requirements of this paragraph.

d. Resources may be, but need not be, EPS-eligible.

e. Purchased power agreements ("PPAs") offering renewable energy must be for a minimum term of five years, but may be for terms, including renewal options, of as long as thirty years.

f. Respondents to this renewable energy RFP must offer products with either fixed prices or relatively stable prices that do not vary with either the price of natural gas or of electricity.

g. Renewable resources must be no more costly, on a levelized cost per MWh basis, than 125% of the reasonably estimated market price of conventional resource alternatives.

h. If APS purchases renewable resources through a PPA, the portion of the cost of those resources that is at or below market price may be recovered through the PSA similar to other PPA costs.

i. If APS purchases through a PPA renewable resources that are not eligible for EPS recovery, the portion of the cost of those resources that is above market price may be recovered through the PSA similar to other PPA costs.

j. If APS purchases through a PPA renewable resources that are eligible to meet EPS requirements, the portion of the cost of those resources that is above market price will be recovered from EPS funds; however, such recovery of cost premiums from EPS funds in any year shall be limited to the kWh, expanded by any applicable multipliers, necessary to meet then-existing EPS requirements for that year. If the portion of the cost that is above market price exceeds the amount that is available from the EPS funds as indicated above, or if the EPS funding is exhausted, the remainder may be recovered through the PSA.

k. The net proceeds from the sale of any environmental credits or tags attributable to the renewable resources acquired pursuant to this paragraph shall be credited to the EPS account.

l. Where feasible, utilization of in-state renewable resources is desirable, subject to the limitations and requirements set forth above, but if APS does not receive sufficient in-state qualified bids, APS is free to acquire qualifying out-of-state resources to meet its initial goal of at least 100 MW or its subsequent goal of acquiring at least ten percent of its incremental capacity needs from renewable resources.

m. Renewable resources acquired through this RFP or pursuant to Section IX that otherwise qualify for EPS treatment will be considered as applying to any EPS standard.

n. Renewable resources acquired through this RFP, through future solicitations for renewables, or pursuant to Section IX shall be subject to the Commission's customary prudence review. The fact that the cost of resources acquired pursuant to this paragraph exceeds market price shall not, in and of itself, render such purchases imprudent.

70. At least thirty days before APS issues the final RFP for renewable resources pursuant to this section, APS will circulate a draft of the RFP to potentially interested parties. At least ten days before APS issues the final RFP, APS will conduct an informal meeting with potential bidders and other interested parties to allow an opportunity for comments and discussion regarding the RFP.

71. If, by December 31, 2006, APS has failed to acquire at least 100 MW of renewable resources pursuant to the RFP described in paragraph 69, APS shall, no later than January 31, 2007, file a notice with the Commission describing the shortfall in renewable resources, explaining the circumstances leading to the shortfall, and recommending actions to the Commission. This notice shall be sent to all Parties of record in this case. Any interested person may request that the Commission conduct a proceeding.

72. The provisions of this section shall not displace APS' requirements under the EPS or any modifications to the EPS.

73. APS will allow and encourage all renewable resources (whether or not EPS-eligible), distributed generation, and DSM proposals to participate in the 2005 RFP or similar competitive solicitation discussed in Section IX.

IX. Competitive Procurement of Power

74. APS will not pursue any self-build option having an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. For purposes of this Agreement, "self-build" does not include the acquisition of a generating unit or interest in a generating unit from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or the up-rating of APS generation, which up-rating shall not include the installation of new units.

75. As part of any APS request for Commission authorization to self-build generation prior to 2015, APS will address:

a. The Company's specific unmet needs for additional long-term resources.

b. The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs.

c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.

d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules or orders resulting from the workshop/rulemaking proceeding described in paragraph 79.

e. The anticipated life-cycle cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for a comparable period of time.

76. Nothing in this section shall be construed as relieving APS of its existing obligation to prudently acquire generating resources, including but not limited to seeking the above authorization to self-build a generating resource or resources prior to 2015.

77. The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

78. Notwithstanding its ability to pursue bilateral agreements with non-affiliates for long-term resources, APS will issue an RFP or other competitive solicitation(s) no later than the end of 2005 seeking long-term future resources of not less than 1000 MW for 2007 and beyond.

a. For purposes of this section, "long-term" resources means any acquisition of a generating facility or an interest in a generating facility, or any PPA having a term, including any extensions exercisable by APS on a unilateral basis, of five years or longer.

b. Neither PWEC nor any other APS affiliate will participate in such RFP or other competitive solicitation(s) for long-term resources, and neither PWEC nor any other APS affiliate will participate in future APS competitive solicitations for long-terms resources without the appointment by the Commission or its Staff of an independent monitor.

c. Nothing in this section shall be construed as obligating APS to accept any specific bid or combination of bids.

d. All renewable resources, distributed generation, and DSM will be invited to compete in such RFP or other competitive solicitation and will be evaluated in a consistent manner with all other bids, including their life-cycle costs compared to alternatives of comparable duration and quality.

79. The Commission Staff will schedule workshops on resource planning issues to focus on developing needed infrastructure and developing a flexible, timely, and fair competitive procurement process. These workshops will also consider whether and to what extent the competitive procurement should include an appropriate consideration of a diverse portfolio of short, medium, and long-term purchased power, utility-owned generation, renewables, DSM, and

distributed generation. The workshops will be open to all stakeholders and to the public. If necessary, the workshops may be followed with rulemaking.

80. APS will continue to use its Secondary Procurement Protocol except as modified by the express terms of this Agreement or unless the Commission authorizes otherwise.

X. Regulatory Issues

81. The Parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area, irrespective of size, and to recognize, in its planning, the existence of any Commission direct access program and the potential for future direct access customers. This section does not bar any Party from seeking to amend APS' obligation to serve.

82. Changes in retail access shall be addressed through the Electric Competition Advisory Group ("ECAG") or other similar process. The ECAG process or similar proceeding shall address, among other things, the resale by Affected Utilities of Revenue Cycle Services ("RCSs") to Electric Service Providers ("ESPs").

83. The Parties further acknowledge that APS currently has the ability, subject to applicable regulatory requirements, to self-build or buy new generation assets for native load, subject to paragraph 81, and subject to the conditions in Section IX of this Agreement.

84. The Parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or an entity or entities performing the functions of an RTO. APS may participate in those activities or similar activities without further order or authorization from the Commission. This paragraph does not establish the ratemaking treatment for costs related to those activities.

85. This section is not intended to create or confirm an exclusive right for APS to provide electric service within its certificated area where others may legally also provide such service, to diminish any of APS' rights to serve customers within its certificated area, or to prevent the Commission or any other governmental entity from amending the laws and regulations relative to public service corporations.

XI. Competition Rules Compliance Charge ("CRCC")

86. Included in the total test year revenue requirement is approximately $8 million for the CRCC. APS may recover $47.7 million plus interest calculated in accordance with paragraph 19.h through a CRCC of $0.000338/kWh over a collection period of five years.

87. When the above amount is recovered, the CRCC will terminate immediately. If any amount remains unrecovered/overrecovered after the end of the five year period, APS shall file an application with the Commission to adjust the CRCC to recover/refund the balance.

88. The CRCC shall be a separate surcharge, i.e., it shall not be included in base rates. The CRCC shall be assessed against all customers except for those served on rate schedules Solar -1 or Solar-2.

89. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the CRCC shall operate.

XII. Low Income Programs

90. APS shall increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000.

91. APS shall increase its E-3 tariff discount levels as follows in Table 1 below:

Table 1 – E-3 Discount Levels		
Usage Level	**Current Discount**	**New Discount**
0-400 kWh	30 %	40 %
401-800 kWh	20 %	26 %
801-1200 kWh	10 %	14 %
Over 1200 kWh	$10.00	$13.00

92. APS shall increase its E-4 tariff discount levels as follows in Table 2 below:

Table 2 – E-4 Discount Levels		
Usage Level	**Current Discount**	**New Discount**
0-800 kWh	30 %	40 %
801-1400 kWh	20 %	26 %
1401-2000 kWh	10 %	14 %
Over 2000 kWh	$20.00	$26.00

93. It is the Parties' intent to insulate eligible low income customers from the effects of the rate increase resulting from this Agreement. With the revisions to the E-3 and E-4 tariff discounts set forth above, eligible low income customers will receive a net reduction in rates.

XIII. Returning Customer Direct Access Charge

94. The Returning Customer Direct Access Charge ("RCDAC") shall be established, subject to the following conditions approved in Decision No. 66567:

a. The charge shall apply only to individual customers or aggregated groups of customers of 3 MW or greater.

b. The charge shall not apply to a customer who provides APS with one year's advance notice of intent to take Standard Offer service.

c. The RCDAC rate schedule shall include a breakdown of the individual components of the potential charge, definitions of the components, and a general framework that describes the way in which the RCDAC would be calculated.

95. The RCDAC shall only be established to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to standard offer service from their competitive suppliers. The RCDAC shall not last longer than twelve months for any individual customer.

96. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the RCDAC shall operate.

XIV. Service Schedule Changes

97. The Company's proposed Schedule 1 changes shall be adopted as modified by Staff. Attached as Appendix C is Schedule 1 with the modifications provided for by this Agreement.

98. The Company's changes to Schedule 3 proposed in its direct testimony shall be adopted but with the retention of the 1,000-foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Attached as Appendix D is Schedule 3 with the modifications provided for by this Agreement.

99. The Company's changes to Schedule 7 proposed in its direct testimony shall be adopted except that the changes reflecting current ANSI standards shall not be made at this time and the words "meter maintenance and testing program" will remain. Attached as Appendix E is Schedule 7 with the modifications provided for by this Agreement.

100. The Company's changes to Schedule 10 proposed in its direct testimony shall be adopted except for the amendments described in Staff's direct testimony, which shall be interpreted as consistent with the current provisions of A.A.C. R14-2-1612. Attached as Appendix F is Schedule 10 with the modifications provided for by this Agreement.

101. Schedules 4 and 15 as set forth in APS' Application shall be approved. Appendix G is Schedule 4 with the modifications provided for by this Agreement. Appendix H is Schedule 15 with the modifications provided for by this Agreement.

102. The Commission may change the service schedules as a result of the ECAG or other similar process.

XV. Nuclear Decommissioning

103. Decommissioning costs shall be as proposed in APS' direct testimony. Attached as Appendix I is the level of decommissioning costs authorized and included in APS' total settlement test year revenue requirement.

XVI. Transmission Cost Adjustor

104. A transmission cost adjustor ("TCA") shall be established in order to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. The TCA shall be limited to recovery (refund) of costs associated with changes in APS' open access transmission tariff ("OATT") or the tariff of an RTO or similar organization.

105. Whenever APS files an application with FERC to change its transmission rates, it shall file a notice with the Commission of its application. APS shall at the same time also provide a copy of its application to the Director of the Utilities Division.

106. The TCA shall not take effect until the transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. When this trigger amount is reached, APS may file for Commission approval of a TCA rate.

107. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the TCA shall operate.

XVII. Distributed Generation

108. Commission Staff shall schedule workshops to consider outstanding issues affecting distributed generation. Staff shall refer to the results of prior distributed generation workshops when determining the specific issues that will benefit from further study.

109. If necessary, the workshops may be followed with rulemaking.

XVIII. Bark Beetle Remediation

110. APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed test year levels of tree and brush control. The deferral account established for this purpose shall not accrue interest.

111. In the Company's next general rate proceeding, the Commission will determine the reasonableness, the prudence, and the appropriate allocation between distribution and transmission of these costs. The Commission will also determine an appropriate amortization period for the approved costs.

XIX. Rate Design

112. *The rates set forth in this Agreement* are designed to permit APS to recover an additional $67.5 million in base revenues as compared to adjusted test year base revenues.

113. APS' residential rate class will generate an additional 3.94% of base revenue compared with adjusted test year base revenue. Each bundled residential rate schedule will have the same basic structure (i.e., number and size of blocks, time-of-use time periods) as APS' existing base rates. Base rate levels shall recover the required revenue and shall permit cost-based unbundling of Distribution and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical.

114. Schedule E-10 and Schedule EC-1 will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in its next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-10 and EC-1 will each generate an additional 4.82% of base revenue compared with adjusted test year base revenue.

115. Schedules E-12, ET-1, and ECT-1R will each generate an additional 3.8% of base revenue compared with adjusted test year base revenue.

116. APS will continue on-peak and off-peak rates for winter billing periods for all residential time-of-use customers served under Schedules ET-1 and ECT-1R. Within 180 days of a final decision in this proceeding, APS will submit a study to Staff that examines ways in which APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, including making on-peak periods more reflective of the times of actual system peak. Before designing its study, APS shall consult with Staff to ensure that the study will address all relevant issues. Time-of-use issues will be reexamined in APS' next rate case.

117. APS' proposed experimental time-of-use periods for ET-1 and ECT-1R will be adopted. Annual reports evaluating the outcomes of adopting these additional time-of-use periods will be filed with Staff. The first report will be due 12 months from the date of a decision in this matter. The report shall make a recommendation regarding the continuation of the experimental time-of-use periods. Before preparing its report, APS shall consult with Staff to ensure that the report will address all relevant issues. These experimental time-of-use periods will be reexamined in APS' next rate case.

118. The existing 11:00 AM to 9:00 PM on-peak time periods shall remain for general service customers served on time-of-use schedules. The summer rate period shall begin with the first billing cycle in May and conclude with the last billing cycle in October. As part of APS' compliance filing, APS and Staff shall meet and confer to review the General Service schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

119. General Service rate schedules will be modified such that Schedules E-32, E-32R, E-34, E-35, E-53, E-54, and the contracts shown in the General Service section of the H schedules attached to APS' rate Application will each generate approximately 3.5% of additional base revenue compared with adjusted test year base revenue. The settlement rate designs for these rate schedules shall permit cost-based unbundling of Generation and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical. With regard to Schedules E-32, E-34, and E-35, the non-system-benefits revenue requirement assigned to the General Service class will be used to establish first the unbundled component of generation at cost and then the unbundled component of revenue cycle services at cost.

120. APS will establish an additional Primary Service Discount of $2.74/kW for military base customers served directly from APS substations.

121. Schedule E-32 has been modified in an effort to simplify the design, to make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes to Schedule E-32 include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. In addition, a time-of-use option will be made available to E-32 customers without restriction as to number of participants.

122. Schedules E-20, E-30, E-40, E-51, E-59 and E-67 will be increased by 5% compared to adjusted test year base revenue. Schedule E-20 shall be frozen. Schedules E-22, E-23 and E-24 will be frozen to new customers and will not be eliminated in this proceeding. APS will provide notice to customers on schedules E-21, E-22, E-23, and E-24 that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-21, E-22, E-23, and E-24 will be increased by 5% compared to adjusted test year base revenue. Rate levels shall recover the required base revenue and permit cost-based unbundling of Generation and Revenue Cycle Services to the degree practical.

123. Frozen rates E-38 (Agricultural Irrigation Service) and E-38T (Agricultural Irrigation Service Time of Use option) will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. Schedule E-38, Schedule E-38T, and Schedule E-221 (including options) will be increased to generate an additional 5% of base revenue compared with adjusted test year base revenue.

124. Dusk to Dawn Lighting (Schedule E-47) and Street Lighting Service (Schedule E-58) will be modified as proposed in APS' Application. Specific charges in these schedules will be increased to generate an additional 5% in base revenue compared with adjusted test year base revenue.

125. Except as modified by this Agreement and to the extent not inconsistent with this Agreement, APS' rate design as proposed in its Application is adopted. As part of APS'

compliance filing, APS and Staff shall meet and confer to review APS' rate schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

126. The specific rate designs for each of the residential rate schedules and for general service rate schedules E-32, E-32 TOU, E-34, and E-35 are set forth in Appendix J. The remaining rates shall be filed by APS as otherwise provided for in this Agreement and in accordance with the compliance filing called for in paragraph 135.

XX. Litigation and Other Issues

127. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS shall dismiss with prejudice all of its appeals of Commission Decision No. 65154, the Track A order, and APS and its affiliates shall also dismiss any and all litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract.

128. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS and its affiliates shall forego any claim that APS, PWEC, Pinnacle West Capital Corporation ("PWCC"), or any of APS' affiliates were harmed by Commission Decision No. 65154.

129. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, the Preliminary Inquiry, ordered in Commission Decision No. 65796, shall be concluded with no further action by the Commission.

XXI. Commission Evaluation of Proposed Settlement

130. The Parties agree that all currently filed testimony and exhibits shall be accepted into the Commission's record as evidence.

131. The Parties recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

132. This Agreement shall serve as a procedural device by which the Parties will submit their proposed settlement of APS' pending rate case, Docket No. E-01345A-03-0437, to the Commission. Except for paragraphs 9, 137, 138, 139, 140, and 143, this Agreement will not have any binding force or effect until its provisions are adopted as an order of the Commission.

133. The Parties further recognize that the Commission will independently consider and evaluate the terms of this Agreement.

134. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Parties shall abide by the terms as approved by the Commission.

DECISION NO. 67744

135. Within sixty days after the Commission issues an order in this matter. APS shall file compliance tariffs for Staff review and approval. Subject to such review and approval, such compliance tariffs will become effective upon filing for billing cycles on and after that date.

136. If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Parties may withdraw from this Agreement, and such Party or Parties may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Party choosing to withdraw from the Agreement. If a Party withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Parties, except for Staff, shall support the application for rehearing by filing a document to that effect with the Commission. Staff shall not be obligated to file any document or take any position regarding the withdrawing Party's application for rehearing.

XXII. Miscellaneous Provisions

137. Nothing in this Agreement shall be construed as an admission by any of the Parties that any of the positions taken by any Party in this proceeding is unreasonable or unlawful. In addition, acceptance of this Agreement by any of the Parties is without prejudice to any position taken by any Party in these proceedings.

138. This Agreement represents the Parties' mutual desire to compromise and settle disputed issues in a manner consistent with the public interest. None of the positions taken in this Agreement by any of the Parties may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except in furtherance of this Agreement.

139. This case presents a unique set of circumstances and has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because the Agreement, as a whole, with its various provisions for settling the unique issues presented by this case, is consistent with their long-term interests and with the broad public interest. The acceptance by any Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

140. All negotiations relating to this Agreement are privileged and confidential. No Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. Evidence of conduct or statements made in the course of negotiating this Agreement shall not be admissible before this Commission, any other regulatory agency, or any court.

141. The "Definitive Text" of the Agreement shall be the text adopted by the Commission in an order that approves all material terms of the Agreement, including all modifications made by the Commission in such an order.

142. Each of the terms of the Definitive Text of the Agreement is in consideration and support of all other terms. Accordingly, the terms are not severable.

143. The Parties shall support and defend this Agreement before the Commission. Subject to paragraph 9, if the Commission adopts an order approving all material terms of this Agreement, the Parties will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

DATED this 18th day of August, 2004.

ARIZONA CORPORATION COMMISSION

By ______________________
Ernest G. Johnson
Director Utilities Division
1200 West Washington
Phoenix, AZ 85007

ARIZONA PUBLIC SERVICE COMPANY

By ______________________
Steven M. Wheeler
Executive Vice President

RESIDENTIAL UTILIY CONSUMER OFFICE

By ______________________
Stephen Ahearn, Director

DECISION NO. 67744

EXHIBIT 4

APS Schedule DGR-8RB

Docket No. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY
Operating Income
Total Company
(Thousands of Dollars)

Line No.	Description		Total	Redhawk Combined Cycle Unit No. 1	Redhawk Combined Cycle Unit No. 2	West Phoenix Combined Cycle Unit No. 5	West Phoenix Combined Cycle Unit No. 4	Saguaro Combustion Turbine No. 3	Redhawk Transmission
1.	**REVENUES:**								
2	Operating Revenue		$ 56,779	$ 12,552	$ 12,542	$ 21,514	$ 6,649	$ 2,264	$ 1,258
3.	Fuel and Purchased Power Expenses		(34,970)	(17,732)	(17,732)	(959)	1,477	(24)	-
4.	Op Rev Less Fuel & Purchased Power Exp		$ 91,749	$ 30,284	$ 30,274	$ 22,473	$ 5,172	$ 2,288	$ 1,258
5.	**EXPENSES:**								
6.	Other Operating Expenses								
7.	Operations Excluding Fuel Expenses		14,110	4,729	4,702	3,535	913	190	41
8.	Maintenance		18,549	5,315	5,327	5,547	1,182	566	612
9.	Sub-total O&M Expenses		$ 32,659	$ 10,044	$ 10,029	$ 9,082	$ 2,095	$ 756	$ 653
10.	Depreciation and Amortization		41,541	11,494	11,494	13,210	2,821	1,375	1,147
11.	Administrative and General		8,797	2,414	2,411	2,585	654	292	441
12.	Other Taxes		11,256	2,990	2,995	2,768	1,248	707	548
13.	Total Other Operating Expenses		$ 94,253	$ 26,942	$ 26,929	$ 27,645	$ 6,818	$ 3,130	$ 2,789
14.	**OPERATING INCOME (before income tax)**		**$ (2,504)**	**$ 3,342**	**$ 3,345**	**$ (5,172)**	**$ (1,646)**	**$ (842)**	**$ (1,531)**
15.	Interest Expense		36,179	9,929	9,914	10,633	2,689	1,201	1,813
16.	Taxable Income		$ (38,683)	$ (6,587)	$ (6,569)	$ (15,805)	$ (4,335)	$ (2,043)	$ (3,344)
17.	Income Tax at	39.5%	(15,280)	(2,602)	(2,595)	(6,243)	(1,712)	(807)	(1,321)
18.	**OPERATING INCOME AFTER TAX**		$ 12,776	$ 5,944	$ 5,940	$ 1,071	$ 66	$ (35)	$ (210)

EXHIBIT 5

Attachment KCH-2

AECC Adjustments to PWEC O&M and A&G Expenses

Total Company
(Thousands of Dollars)

Line No.	Description	(a) APS Amount in Filing	(b) AECC Recommended Amount	(c) = (b) - (a) AECC Adjustment
1	REVENUES:			
2	Operating Revenue			
3	Fuel and Purchased Power Expense			
4	Operating Revenue less Fuel and Purchased Power Expenses			
5	EXPENSES:			
6	Other Operating Expense			
7	Operations Excluding Fuel & Purchased Power Expenses	26,204 /1	21,353 /2	(4,851)
8	Maintenance (Overhaul)	10,000 /1	11,238 /2	1,238
9	O&M Subtotal	36,204	32,591	(3,613)
10	Depreciation and Amortization			
11	Amortization of Gain			
12	Administrative and General	20,415 /1	8,797 /2	(11,618)
13	Other Taxes			
14	Total	56,619	41,388	(15,231)
15	OPERATING INCOME (before imcome tax)	(56,619)	(41,388)	15,231
16	Interest Expense			
17	Taxable Income	(56,619)	(41,388)	15,231
18	Income Tax @ 39.05%	(22,110)	(16,162)	5,948
19	OPERATING INCOME AFTER TAX	(34,509)	(25,226)	9,283

Data Sources:
Note 1 - APS Workpaper LLR_WP13, pp. 2 & 3 of 11.
Note 2 - APS Schedule DGR-8RB, p. 3 of 4 in ACC Docket E-01345A-03-0437.

AECC Adjustments to PWEC O&M and A&G Expenses

(Thousands of Dollars)

Line No.	Description	(a) Total Company Adjustment	(b) ACC Jurisdictional Adjustment
1	REVENUES:		
2	Operating Revenue	0	0
3	Fuel and Purchased Power Expense	0	0
4	Operating Revenue less Fuel and Purchased Power Expenses	0	0
5	EXPENSES:		
6	Other Operating Expense		
7	Operations Excluding Fuel & Purchased Power	(4,851)	(4,795)
8	Maintenance (Overhaul)	1,238	1,224
9	O&M Subtotal	(3,613)	(3,571)
10	Depreciation and Amortization	0	0
11	Amortization of Gain	0	0
12	Administrative and General	(11,618)	(11,484)
13	Other Taxes	0	0
14	Total	(15,231)	(15,056)
15	OPERATING INCOME (before imcome tax)	15,231	15,056
16	Interest Expense	0	0
17	Taxable Income	15,231	15,056
18	Income Tax @ 39.05%	5,948	5,879
19	OPERATING INCOME AFTER TAX	9,283	9,176
20	Gross Revenue Conversion Factor		1.640703
21	Impact on Revenue Requirement (-Ln 19 x Ln 20)		(15,056)

EXHIBIT 6

Towers-Perrin Report

MS-6

Basic Results for Pension Cost

	January 1, 2005	January 1, 2004
Service Cost	$	$
Obligations		
Accumulated benefit obligation [ABO]:		
► Participants currently receiving benefits	$	$
► Deferred inactive participants		
► Active participants		
Total ABO	$ 1,138,547,050	$
Obligation due to future salary increases	233,022,680	
Projected benefit obligation [PBO]	$ 1,371,569,730	$
Assets		
Fair value [FV]	$ 982,282,105	$
Unrecognized investment losses (gains)	0	
Market-related value	$ 982,282,105	$
Funded Position		
Unfunded PBO	$ 389,287,625	$
Minimum liability [ABO – FV, minimum zero]	156,264,945	

CONFIDENTIAL

APS07382

EXHIBIT 7

Attachment KCH-3

AECC Adjustments to Pension Expense

Total Company
(Thousands of Dollars)

Line No.	Description	(a) APS Amount in Filing	(b) AECC Recommended Amount	(c) = (b) - (a) AECC Adjustment
1	REVENUES:			
2	Operating Revenue			
3	Fuel and Purchased Power Expense			
4	Operating Revenue less Fuel and Purchased Power Expenses			
5	EXPENSES:			
6	Other Operating Expense			
7	Operations Excluding Fuel & Purchased Power Expenses	43,695 /1	0	(43,695)
8	Maintenance (Overhaul)			
9	O&M Subtotal	43,695	0	(43,695)
10	Depreciation and Amortization			
11	Amortization of Gain			
12	Administrative and General			
13	Other Taxes			
14	Total	43,695	0	(43,695)
15	OPERATING INCOME (before imcome tax)	(43,695)	0	43,695
16	Interest Expense			
17	Taxable Income	(43,695)	0	43,695
18	Income Tax @ 39.05%	(17,063)	0	17,063
19	OPERATING INCOME AFTER TAX	(26,632)	0	26,632

Data Sources:
Note 1 - APS Workpaper LLR_WP22, pp. 2 of 2.

AECC Adjustments to Pension Expense

(Thousands of Dollars)

Line No.	Description	(a) Total Company Adjustment	(b) ACC Jurisdictional Adjustment
1	REVENUES:		
2	Operating Revenue	0	0
3	Fuel and Purchased Power Expense	0	0
4	Operating Revenue less Fuel and Purchased Power Expenses	0	0
5	EXPENSES:		
6	Other Operating Expense		
7	Operations Excluding Fuel & Purchased Power	(43,695)	(41,166)
8	Maintenance (Overhaul)	0	0
9	O&M Subtotal	(43,695)	(41,166)
10	Depreciation and Amortization	0	0
11	Amortization of Gain	0	0
12	Administrative and General	0	0
13	Other Taxes	0	0
14	Total	(43,695)	(41,166)
15	OPERATING INCOME (before imcome tax)	43,695	41,166
16	Interest Expense	0	0
17	Taxable Income	43,695	41,166
18	Income Tax @ 39.05%	17,063	16,075
19	OPERATING INCOME AFTER TAX	26,632	25,091
20	Gross Revenue Conversion Factor		1.640703
21	Impact on Revenue Requirement (-Ln 19 x Ln 20)		(41,166)

EXHIBIT 8

Scates v. Arizona Corp. Commission

Document Retrieval Result Westlaw.

Scates v. Arizona Corp. Commission
118 Ariz. 531, 578 P.2d 612
Ariz.App.,1978.
Feb 03, 1978

118 Ariz. 531, 578 P.2d 612
Court of Appeals of Arizona,Division 1,Department B.
Edward G. SCATES and Rozella Castillo, Appellants,
v.
ARIZONA CORPORATION COMMISSION, Al Faron, Bud Tims, and Ernest Garfield, Members of the Arizona Corporation Commission, and Mountain States Telephone and Telegraph Company, Appellees.
No. 1 CA-CIV 3669.
Feb. 3, 1978.
Rehearings Denied April 20, 1978.
Reviews Denied May 9, 1978.

The Arizona Corporation Commission approved an application by telephone company for an increase in rates. The Superior Court, Maricopa County, Cause No. C-327026, Rufus C. Coulter, Jr., J., upheld Commission's order on summary judgment, and appeal was taken. The Court of Appeals, Schroeder, J., held that Commission's action in approving increase without any examination of costs of utility apart from affected services, without any determination of utility's investment, and without any inquiry into effect of substantial increase upon utility's rate of return on investments, violated Arizona's constitutional provisions regarding rate making.
Reversed and remanded.

West Headnotes

[1] KeyCite this headnote

317A Public Utilities
  317AII Regulation
    317Ak119 Regulation of Charges
      317Ak124 k. Value of Property; Rate Base. Most Cited Cases
        (Formerly 317Ak7.5)

317A Public Utilities KeyCite this headnote
  317AII Regulation
    317Ak119 Regulation of Charges
      317Ak129 k. Rate of Return. Most Cited Cases
        (Formerly 317Ak7.10)

General theory of utility regulation is that total revenue, including income from rates and charges, should be sufficient to meet utility's operating costs and to give utility and its stockholders a reasonable rate of return on utility's investment; to achieve this, Corporation Commission must first determine "fair value" of utility's property and use such value as utility's rate base, and then must determine what rate of return should be and apply that figure to rate base in order to establish just and reasonable tariffs. A.R.S.Const. art. 15, § 3; A.R.S. § 40-250.

[2] KeyCite this headnote

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak124 k. Value of Property; Rate Base. Most Cited Cases
(Formerly 317Ak7.5)

While Corporation Commission has broad discretion in establishing rates, it is required by the Constitution to ascertain value of utility's property within state in setting just and reasonable rates. A.R.S.Const. art. 15, § 14.

[3] KeyCite this headnote

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak129 k. Rate of Return. Most Cited Cases
(Formerly 317Ak7.10)

Rates established by Corporation Commission should meet overall operating costs of utility and produce reasonable rate of return; rates cannot be considered just and reasonable if they fail to produce reasonable rate of return or if they produce revenue which exceeds a reasonable rate of return.

[4] KeyCite this headnote

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak130 k. Temporary or Emergency Charges. Most Cited Cases
(Formerly 317Ak7.11)

"Interim rate" is rate permitted to be charged by utility for products or services pending establishment of a permanent rate.

[5] KeyCite this headnote

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak128 k. Operating Expenses. Most Cited Cases
(Formerly 317Ak7.9)

"Automatic adjustment clause" is a device to permit utility rates to adjust automatically, either up or down, in relation to fluctuations in certain narrowly defined operating expenses and usually embodies a formula established during rate hearing to permit adjustment of rates in future to reflect changes in specific operating costs, such as wholesale cost of gas or electricity.

[6] KeyCite this headnote

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges

317Ak128 k. Operating Expenses. Most Cited Cases
(Formerly 317Ak7.9)

Although a utility may receive increased gross revenues when utility rates increase under automatic adjustment clauses, a utility's net income should not be increased since operating costs also will have risen to offset increased revenue.

[7] KeyCite this headnote

372 Telecommunications
372III Telephones
372III(G) Rates and Charges
372k966 Administrative Procedure
372k968 k. Powers of Commissions and Agencies. Most Cited Cases
(Formerly 372k334)

Corporation Commission, which approved increase of almost $5,000,000 on rates charged for certain telephone services with no concomitant reduction in charges for other services without any inquiry whatsoever into whether increased revenues resulted in rate of return greater or less than that established in rate hearing some ten months before, and which expressly rejected all evidence bearing on the subject, was without authority to increase rate without any consideration of overall impact of that rate increase upon return of telephone utility and without specifically required determination of utility's rate base. A.R.S.Const. art. 15, § 3; A.R.S. § 40-250.

[8] KeyCite this headnote

372 Telecommunications
372III Telephones
372III(G) Rates and Charges
372k974 Judicial Review or Intervention
372k978 k. Presentation and Reservation of Grounds of Review. Most Cited Cases
(Formerly 372k341)

Where individual customers argued at all times that Corporation Commission lacked authority to increase telephone utility's rates without considering impact of increase on overall financial condition of utility and specifically without taking into account rate base and effect of increase on rate of return, and principal authorities relied upon before Commission were same as those relied on in superior court and before Court of Appeals, validity of Commission's approval of application for increase in rates was properly before the Court of Appeals. A.R.S. § 40-253[C].
***533 **614** Arizona Center for Law in the Public Interest by Kenneth Sundlof, Bruce Meyerson, Phoenix, for appellants.
Bruce E. Babbitt, Atty. Gen., by Charles S. Pierson, Michael M. Grant, Asst. Attys. Gen., Phoenix, for appellees, Arizona Corp. Commission.
Fennemore, Craig, von Ammon & Udall, P. C., by C. Webb Crockett, George T. Cole, Phoenix, for appellees, Mountain States Tel. & Tel. Co.

OPINION

SCHROEDER, Judge.
This appeal concerns the validity of the Arizona Corporation Commission's approval of an application by Mountain States Telephone and Telegraph Company for an increase in rates. The increase affected charges for all installation, moving and changing of telephones within the State of Arizona. It amounted to an annual rise in revenue to Mountain States of approximately

4.9 million dollars, representing about two percent of its entire annual revenue in the state. The Commission approved the increase without any examination of the costs of the utility apart from the affected services, without any determination of the utility's investment, and without any inquiry into the effect of this substantial increase upon Mountain States' rate of return on that investment. We hold that the Commission's action was in violation of Arizona's constitutional provisions regarding rate making as consistently interpreted by the courts of this state, and we reverse the judgment of the trial court upholding the increase.

The application in question was filed by Mountain States on November 4, 1975, and public hearings were held on December 2 and 3, 1975. This application was filed approximately ten months after the Commission had conducted a full scale hearing to establish rates for all Mountain States' services. The hearing on this application was also held approximately two months prior to the scheduled date for another general rate hearing, set for February, 1976.

At the hearing on this application, several parties were permitted to intervene. They included businesses and the appellants herein, Edward Scates and Rozella Castillo who, as individual customers of Mountain States, would be affected by the requested increase. Throughout the hearing the Commission took the view that this increase should be considered solely on the basis of evidence reflecting the costs of these particular services. Thus, Mountain States put on evidence that the charges for these particular services, approved at the last rate hearing, covered only approximately 41 percent of the company's costs for those services, and that the increases sought would cover approximately 64 percent of costs. However, Mountain States' own attempt to submit summary data, based upon the prior submissions to the Commission showing the effect of the proposed increase on its rate of return was rejected by the Commission, and all references to the effect of this increase on the company's overall financial condition were stricken.

On December 12, 1975, the Commission approved the increase as requested by Mountain States, summarily concluding that it was just and reasonable, and ordered its immediate implementation. A motion for rehearing was filed by the appellants, and after its denial, the appellants filed this action in the Superior Court. The Superior Court, on summary judgment, upheld the Commission's order, and this appeal followed.

[1] In Arizona, the Corporation Commission is the body charged with the responsibility for establishing utility rates which are "just and reasonable." Ariz.Const. art. 15, s 3; A.R.S. s 40-250. The general theory of utility regulation is that the total revenue, including income from rates and charges, should be sufficient to meet a utility's operating costs and to give the utility ***534 **615** and its stockholders a reasonable rate of return on the utility's investment. See Simms v. Round Valley Light & Power Co., 80 Ariz. 145, 153, 294 P.2d 378, 383 (1956); see generally Phillips, The Economics of Regulation 178-302 (Rev. ed. 1969). To achieve this, the Commission must first determine the "fair value" of a utility's property and use this value as the utility's rate base. Arizona Corp. Comm'n v. Arizona Pub. Serv. Co., 113 Ariz. 368, 370, 555 P.2d 326, 328 (1976). The Commission then must determine what the rate of return should be, and then apply that figure to the rate base in order to establish just and reasonable tariffs. Id.

[2] While the Corporation Commission has broad discretion in establishing rates, id., it is required by our Constitution to ascertain the value of a utility's property within the State in setting just and reasonable rates. Ariz.Const. art. 15, s 14.

An early case so interpreting our Constitution is State v. Tucson Gas, Electric Light & Power Co., 15 Ariz., 294, 138 P. 781 (1914), in which the Court stated that s 14 was written into our Constitution in order for the Corporation Commission to "act intelligently, justly and fairly between the public service corporations doing business in the state and the general public . . . ." Id. at 303, 138 P. at 784. The court went on to state the

" 'fair value of the property' of public service corporations is the recognized basis upon which rates and charges for services rendered should be made, and it is made the duty of the Commission to ascertain such value, not for legislative use, but for its own use, in arriving at just and reasonable rates and charges . . . ." Id. at 303, 138 P. at 785.

In a later case, while considering whether the Commission could reduce the rates without determining the fair value, our Supreme Court affirmed the principle that the value of a utility's property must be considered in setting just and reasonable rates:

"It is clear . . . that under our constitution as interpreted by this court, the commission is required to find the fair value of (the utility's) property and use such finding as a rate base for the purpose of calculating what are just and reasonable rates. . . . While our constitution does not establish a formula for arriving at fair value, it does require such value to be found and used as the base in fixing rates. The reasonableness and justness of the rates must be related to this finding of fair value." Simms v. Round Valley Light & Power Co., 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956).

[3] *Thus, the rates established by the Commission should meet the overall operating costs of the utility and produce a reasonable rate of return.* It is equally clear that the rates cannot be considered just and reasonable if they fail to produce a reasonable rate of return or if they produce revenue which exceeds a reasonable rate of return.

In this case, the Corporation Commission approved an increase of almost five million dollars on the rates charged for certain services with no concomitant reduction in the charges for other services. The resulting net increase in revenue to the utility was accomplished without any inquiry whatsoever into whether the increased revenues resulted in a rate of return greater or lesser than that established in the rate hearing some ten months before. All evidence bearing on the subject was expressly rejected. Although all parties before the Commission generally agreed that it would be improper to implement an increase of all rates without such inquiry, we see no justification for permitting the same increase in revenues to be accomplished by raising only some of the tariffs. As special counsel for the Commission's staff pointed out during the course of this hearing, such a piecemeal approach is fraught with potential abuse. Such a practice must inevitably serve both as an incentive for utilities to seek rate increases each time costs in a particular area rise, and as a disincentive for achieving countervailing economies in the same or other areas of their operations.

In support of its position, Mountain States points to two situations in which ***535 **616** some courts have permitted rate increases to be effected without a simultaneous determination of their effect on the company's rate of return. These are interim rate increases and increases caused by the use of automatic adjustment clauses. On close analysis, these devices do not provide any support for the Commission's action in this case.

[4] An interim rate is a rate permitted to be charged by the utility for products or services pending the establishment of a permanent rate.

"Interim rates are employed to fill a hiatus which occurs between the time that existing rates being charged by a public service corporation have been invalidated by a court or have been determined by the appropriate regulatory body to be confiscatory of the corporation's property, and the time that permanent rates which produce a fair return are established." 71-17 Op. Att'y Gen. (1971).

In Arizona, our Supreme Court has allowed the Superior Court to authorize such a temporary increase pending a final determination by the Commission of permanent rates. Arizona Corp. Comm'n v. Mountain States Telephone & Telegraph Co., 71 Ariz. 404, 228 P.2d 749 (1951). The Attorney General has concluded, based upon this authority, that the Commission itself may establish such interim rates, but only with appropriate safeguards to insure that rates will not become permanent until there is adequate inquiry into whether they are just and reasonable. The opinion goes on to point out that such a device should be used only in limited situations where an emergency exists, where a bond is posted guaranteeing a refund to the utility's subscribers if any payments are made in excess of the rates eventually determined by the Commission, and where a final determination of just and reasonable rates is to be made by the Commission after it values a utility's property. The action of the Commission in the instant case in approving a permanent increase lacked all of these safeguards and was not in any material way similar to adoption of an interim rate increase.

[5] The automatic adjustment clause is a device to permit rates to adjust automatically, either up or down, in relation to fluctuations in certain, narrowly defined, operating expenses. See generally, Foy, Cost Adjustment in Utility Rate Schedules, 13 VandL.Rev. 663 (1960); Trigg, Escalator Clauses in Public Utility Rate Schedules, 106 U.Pa.L.Rev. 964 (1958); Note, Due Process Restraints on the Use of Automatic Adjustment Clauses in Utility Rate Schedules, 18 Ariz.L.Rev. 454 (1976). Such clauses usually embody a formula established during a rate

hearing to permit adjustment of rates in the future to reflect changes in specific operating costs, such as the wholesale cost of gas or electricity. E. g., Consumers Organization for Fair Energy Equality, Inc. v. Department of Pub. Utilities, 335 N.E.2d 341, 343 (Mass.Sup.Jud.Ct.1975); City of Norfolk v. Virginia Electric & Power Co., 197 Va. 505, 90 S.E.2d 140, 148 (1955).

"(T)he impact of certain increased or decreased costs are passed on to the consumer so that the utility neither benefits from a decreased cost nor suffers a diminished return as a result of an increase in a cost covered by the adjustment clause." 71-15 Op. Att'y Gen. (1971).

[6] Thus, although a utility may receive increased gross revenues when utility rates increase under automatic adjustment clauses, a utility's net income should not be increased, because operating costs also will have risen to offset the increased revenue. See Maestas v. New Mexico Pub. Serv. Comm'n, 85 N.M. 571, 514 P.2d 847 (1973).

When courts have upheld such automatic adjustment provisions, they have generally done so because the clauses are initially adopted as part of the utility's rate structure in accordance with all statutory and constitutional requirements and, further, because they are designed to insure that, through the adoption of a set formula geared to a specific readily identifiable cost, the utility's profit or rate of return does not change. E. g., ***536 **617*** Consumers Organization for Fair Energy Equality, Inc. v. Department of Pub. Utilities, 335 N.E.2d 341 (Mass.Sup.Jud.Ct.1975); State ex rel. Utilities Comm'n v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976); City of Norfolk v. Virginia Electric & Power Co., 197 Va. 505, 90 S.E.2d 140 (1955). See also 71-17 Op. Att'y Gen. (1971). In State ex rel. Utilities Comm'n v. Edmisten, the Court, for example, in justifying the use of the clause to isolate only one element of the utility's cost, stated that the clause was

"approved only as an adjunct, or rider, to the utility's other general rate schedules which the Commission had simultaneously under consideration. The Commission approved the clause not as an isolated event but as a rider to general rate schedules in which all elements of cost were duly considered." 230 S.E.2d at 659.

We find no material similarity between the procedure used in this case by the Commission and the adoption of an automatic adjustment clause. The Commission did not consider all of the utility's costs when it approved this raise. The elements of cost which it did consider were not easily segregated costs of specific purchased items such as fuel or electricity; rather they included all the operating expenses underlying moving, installation and changing of telephones. The effect of the increase on the rate of return was ignored.

During the course of the hearing itself, the principal authorities relied upon by the Commission in restricting its inquiry were two North Carolina cases: State ex rel. Utilities Comm'n v. Carolinas Comm. for Indus. Power Rates & Area Dev., Inc., 257 N.C. 560, 126 S.E.2d 325 (1962); State ex rel. Utilities Comm'n v. Carolina Power & Light Co., 250 N.C. 421, 109 S.E.2d 253 (1959). These cases do not support the action of the Commission here.

These cases were decided under a special North Carolina statute authorizing in certain circumstances a "complaint proceeding" rather than a rate proceeding. The court limited use of the North Carolina "complaint proceeding" to situations involving "an emergency or change of circumstances which does not affect the entire rate structure of the utility . . . ." State ex rel. Utilities Comm'n v. Carolina Power & Light Co., 109 S.E.2d at 261. The Commission in this proceeding did not purport to follow any special "complaint" procedure.[FN1] This proceeding was at all times considered to be a proceeding under A.R.S. s 40-250 applying to rate increases.

FN1. A.R.S. ss 40-246 and 249 authorize proceedings known as "complaint proceedings" with respect to rates. An opinion of the Arizona Attorney General suggests that if a complaint proceeding is instituted and the Commission determines that a hearing with respect to a rate change is warranted, then restricted procedures such as those followed by the

Commission in this case would be inappropriate. 69-6 Op. Att'y Gen. (1969).

In addition, the facts in this case are not materially similar to those in the North Carolina cases.

The Commission here never determined that there was an emergency; Mountain States did not claim that there had been a change in circumstances since the last rate hearing and, in fact, admitted that the information in which the increase was based was substantially available at the time of the previous rate hearing. This rate increase does not apply to a very small class of customers, but to all customers who as of and after the date of the increase had phones installed, moved or changed. Moreover, the increase in issue in both North Carolina cases related to the increased cost of fuel, and in both cases there was general financial evidence supporting administrative approval of the rate changes. Thus, in State ex rel. Utilities Comm'n v. Carolina Power & Light Co., the Commission had before it financial statements and balance sheets of the Power Company for the ten preceding years, 109 S.E.2d at 263; in State ex rel. Utilities Comm'n v. Carolinas Comm. for Indus. Power Rates & Area Dev., Inc., the new rate schedule was a modernization designed to produce the same revenue as had been earned under the old schedule. 126 S.E.2d at 328. No such showings have been made here.

Appellees point to the complexity of full scale rate hearings, as illustrated by general order R14-2-128 (formerly designated ****618 *537*** "general order U-53") promulgated by the Corporation Commission requiring very extensive submissions by a utility concerning its financial condition in connection with general rate hearings. Appellees argue that Mountain States should not be required to undergo the time and expense of preparing such submissions anew when all that is sought is a partial rate increase.

The extensive requirements of the order reflect the type of information which, in the Commission's view, should be looked at in order to determine "just and reasonable rates" although we note that the order itself makes provision for a waiver of its requirements in appropriate cases.[FN2]

> FN2. R14-2-128 B. 5. reads as follows: "Waiver of requirements: Either prior to the filing or within 15 days from the date thereof, the Commission, after determining the existence of reasonable cause, by order may waive compliance with any or all of the requirements of this General Order. Such Waiver will be granted only upon written petition to the Commission. In said petition, the utility must demonstrate that the requirements sought to be waived are either not applicable to the rate matter which is the subject of the filing or that compliance therewith would place an undue burden on the utility." The record in this case does not show that any such waiver was sought or granted.

[7] We do not need to decide in this case whether as a matter of law there must be a de novo compliance with all provisions of the order in connection with every increase in rates. The Commission here not only failed to require any such submissions, but also failed to make any examination whatsoever of the company's financial condition, and to make any determination of whether the increase would affect the utility's rate of return. There may well be exceptional situations in which the Commission may authorize partial rate increases without requiring entirely new submissions. We do not decide in this case, for example, whether the Commission could have referred to previous submissions with some updating or whether it could have accepted summary financial information. We do hold that the Commission was without authority to increase the rate without any consideration of the overall impact of that rate increase upon the return of Mountain States, and without, as specifically required by our law, a determination of Mountain States' rate base. Simms v. Round Valley Light & Power Co., 80 Ariz. 145, 294 P.2d 378 (1956); Ariz.Const. art. 15, s 3; A.R.S. s 40-250. The Commission not only failed to make any findings to support its conclusion that the increases were just and reasonable, but it received no evidence upon which such findings could be based.

[8] Finally, appellees argue as a procedural matter that the only question properly before us is whether the Commission should have required and considered entirely new data submissions on all aspects of Mountain States' operations before approving these increases. Appellees assert that such a requirement was the only ground raised on appellants' application for rehearing before the Commission. Appellees rely upon A.R.S. s 40-253(C) which provides that parties may

not rely in court upon the grounds not set forth in an application for rehearing before the Commission.[FN3]

FN3. A.R.S. s 40-253(C) provides: "The application shall set forth specifically the grounds on which it is based, and no person, nor the state, shall in any court urge or rely on any ground not set forth in the application."

We do not construe the application for rehearing filed by appellants in this case as limited to the assertion that entirely new general order R14-2-128 submissions and a de novo determination of rate base were required; rather, appellants argued at all times that the Commission lacked authority to increase Mountain States' rates without considering the impact of the increase on the overall financial condition of the utility and, specifically without taking into account the rate base and the effect of the increase on the rate of return. The principal authorities relied upon before the Commission were the same as those relied upon in the Superior Court and before this Court.

"The purpose of this provision (A.R.S. s 40-253(C)) is to afford the Commission the opportunity to correct its own mistakes before the matter is brought to court. See ***538 **619** State v. Arizona Corporation Comm'n, 94 Ariz. 107, 382 P.2d 222 (1963)." Horizon Moving & Storage Co. v. Williams, 114 Ariz. 73, 75, 559 P.2d 193, 195 (Ct.App.1976). As our Supreme Court stated in State ex rel. Church v. Arizona Corporation Comm'n, 94 Ariz. 107, 382 P.2d 222 (1963), the requirement of A.R.S. s 40-253(C) is satisfied "if the legal or factual point now relied upon was raised in the petition for rehearing." Id. at 112, 382 P.2d at 225.

For the foregoing reasons, the judgment of the Superior Court is reversed and the matter is remanded with instructions to set aside the order of the Corporation Commission entered December 12, 1975.

Reversed and remanded.

EUBANK, P. J., and WREN, J., concur.
Ariz.App.,1978.
Scates v. Arizona Corp. Commission
118 Ariz. 531, 578 P.2d 612
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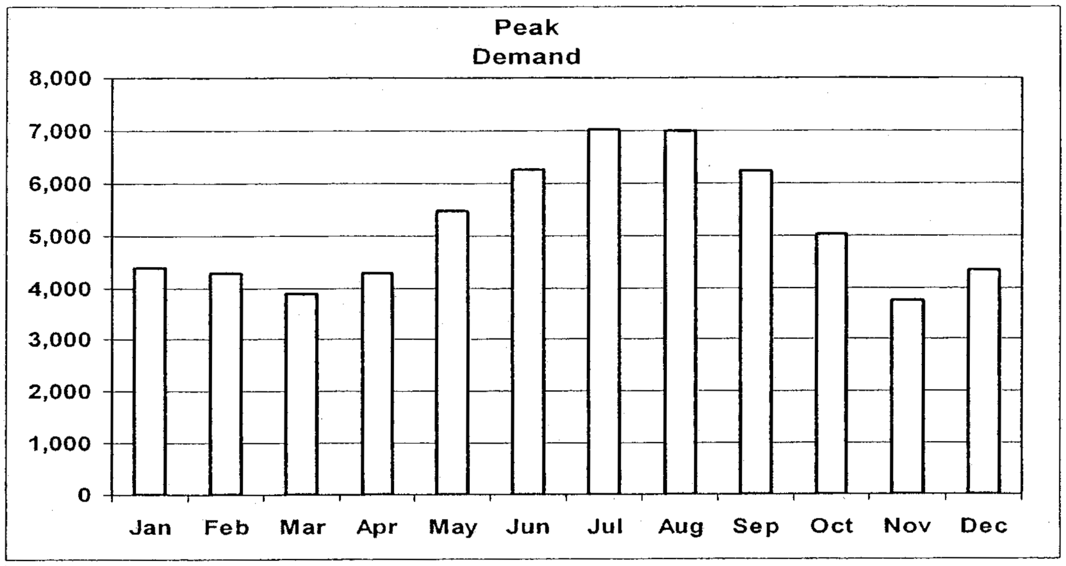
EXHIBIT 9

Direct Testimony of Kevin C. Higgins
Cost of Service

Table KCH-1

Figure KCH-1[1]

APS Monthly Peak Demands



The 4-CP method allocates fixed production and transmission costs based on the average of system peak demands in the four summer months, which is when APS's production and transmission capacity requirements are determined. Such an approach properly aligns the allocation of the Company's fixed costs with cost causation. Both this Commission and the FERC have previously recognized the merit of applying the 4-CP method to APS, given the Company's system load characteristics. I recommend approval of APS's continued use of this method in this proceeding.

III. APS proposed rate spread

Q. What general guidelines should be employed in spreading any change in rates?

[1] Source: APS Workpaper PWE WP-11.

EXHIBIT 10

Direct Testimony of Kevin C. Higgins
Cost of Service

Table KCH-2

Q. Can you provide a simple example of how this transfer of cost responsibility occurs?

A. Yes, let's assume we have two customer classes, Cooling and Manufacturing. Assume further that we have two pricing periods, Winter and Summer, and that the price of energy is $20/MW in Winter and $50/MWh in Summer. Further, assume that the load for Cooling is 10 MWH in Winter and 40 MWH in Summer, whereas for Manufacturing it is 20 MWH in each period. These assumptions are listed in Table KCH-2, below.

Table KCH-2

Average Energy Cost Allocation – Simple Example

Class	Winter P = $20	Summer P = $50	Annual Totals
Cooling Manufacturing System MWH	10 MWH 20 MWH 30 MWH	40 MWH 20 MWH 60 MWH	50 MWH 40 MWH 90 MWH
System Cost Average Energy Cost	$600 $20	$3,000 $50	$3,600 $40
Cost caused by Cooling Cost allocated to Cooling	$200	$2,000	$2,200 $2,000
Cost caused by Manuf. Cost allocated to Manuf.	$400	$1000	$1,400 $1,600

As shown in Table KCH-2, the Winter cost attributable to the Cooling class is $200 ($20 x 10 MWH) and the Summer cost attributable to this class is $2,000 ($50 x 40 MWH) for a total of $2,200. However, the use of average annual energy cost for cost allocation assigns only $2,000 of cost to this class

EXHIBIT 11

Direct Testimony of Kevin C. Higgins
Cost of Service

Table KCH-4

Table KCH-4

Comparison of APS and AECC Cost-of-Service Results
Impact of Using Hourly Energy Allocator

Class	Rate Change Based on APS COS	Rate Change Based on AECC COS
Residential	27.05%	28.74%
General Service	14.88%	13.19%
E-32	13.40%	12.14%
E-34	24.61%	21.60%
E-35	24.85%	18.72%
Water Pumping	(1.15)%	(2.82)%
Street Lighting	42.10%	35.16%
Dusk-to-Dawn	17.78%	14.53%
Total	21.14%	21.14%

Q. What do the results of the re-calculated cost-of-service study show?

A. The net impact on the Residential class of including an hourly energy allocator is relatively modest: the overall cost responsibility for Residential customers increases by 1.69 percent. When rate spread mitigation is taken into account, the net impact on Residential rates is even less. However, the beneficial impact on industrial rate schedules more significant: the cost responsibility for Rate E-34 declines 3.01 percent and that of Rate E-35 declines by 6.13 percent.

This is an important result. It demonstrates that increasing the accuracy of energy cost allocation has a significant beneficial impact for Arizona industry, while having a modest impact on Residential customers. This result is especially important in light of the fact that APS is proposing to set rates for industrial customers exactly at cost-of-service. It is essential, then, that these costs are calculated as accurately as possible.

EXHIBIT 12

Attachment KCH-8

Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

E-32 General Service	Generation Demand Costs (Over 20 kW)[1]	Demand Generation Revenue E-21-24 (Over 20 kW)[2]	Demand Generation Revenue E-32 (1st 200kWh/kW)[3]	Total Demand Generation Revenue
Total	$273,642,337	$3,709,768	$182,147,286	$185,857,054
		Generation Demand Cost Under Collection		($87,785,283)

E-32 General Service	Generation Energy Costs (Over 20 kW)[1]	Energy Generation Revenue E-21-24 (Over 20 kW)[2]	Energy Generation Revenue E-32 (1st 200kWh/kW & All Addt.)[3]	Total Energy Generation Revenue
Total	$315,557,749	$8,086,307	$422,771,992	$430,858,299
		Generation Energy Cost Over Collection		$115,300,550

E-34	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$28,359,773		$19,923,962
		Generation Demand Cost Under Collection	($8,435,811)

E-34	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$37,684,591		$46,201,502
		Generation Energy Cost Over Collection	$8,516,911

E-35	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$26,046,173		$20,968,904
		Generation Demand Cost Under Collection	($5,077,269)

E-35	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$44,903,360		$47,600,181
		Generation Energy Cost Over Collection	$2,696,821

1. Source DJR_WP3
2. Source DJR_WP9
3. See KCH-8 pg. 2 Line 7

Comparison of APS's Generation Cost Components
with APS's Proposed Generation Revenue Components
Derivation of E-32 Demand-Related & Energy-Related Revenues

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Summer	Units	Rate	Line 1 - Line 2	Demand Related Revenue[1]	Energy Related Revenue	Source
1	Gen. - 1st 200kWh/kW	2,642,829,245	$0.09085	$0.03855	$101,881,067	$138,219,970	= Row ((b) x (c)) - (e)
2	Gen. - All Addit. kWh	2,595,455,920	$0.05230			$135,742,345	= Row (b) x (c)
3				Total Summer	$101,881,067	$273,962,314	
	Winter	Units	Rate	Line 4 - Line 5	Demand Related Revenue[1]	Energy Related Revenue[2]	
4	Gen. - 1st 200kWh/kW	2,082,132,784	$0.07555	$0.03855	$80,266,219	$77,038,913	= Row ((b) x (c)) - (e)
5	Gen. - All Addit. kWh	1,939,750,391	$0.0370			$71,770,764	= Row (b) x (c)
6				Total Winter	$80,266,219	$148,809,677	
7				Total Revenue	$182,147,286	$422,771,992	

1. Row (d) x (b)